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EXHIBITS
FOR
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0000020460: ACPA 1-4, AECC 1, 2, AECC/PD/FEA/K 1-3, APS 1-4

0000020461: APS 5-27, APS 33-39

0000020463: APS-R 16-22, APS-SD 1-4, ASP-SR 1-3, AUIA, AUIA-S, AZCA 1-5 & 7-10 (6 NOT USED) CNE/SEL 1-5, DOME VALLEY, FEA 1 & 2, GLEASON 1, IBEW 1, KROGER 1, MESQUITE 1 & 2, MUNDELL 1

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REBUTTAL TESTIMONY OF JACK E. DAVIS

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

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REBUTTAL TESTIMONY OF JACK E. DAVIS
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Jack E. Davis. My business address is 400 North Fifth Street, Phoenix, Arizona 85004. I am President and Chief Executive Officer for Arizona Public Service Company ("APS" or "Company"). I am also a President and Chief Operating Officer of Pinnacle West Capital Corporation ("Pinnacle West").

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My resume is attached as Appendix A to my testimony.

Q. DID YOU PREVIOUSLY SUBMIT WRITTEN TESTIMONY IN THIS RATE PROCEEDING?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I strongly disagree with Utilities Division Staff ("Staff") witnesses Linda A. Jaress and Lee Smith concerning: (1) the results of Staff's "preliminary inquiry" into the relationship between APS and certain of its affiliated entities; and (2) whether APS has been hurt by the Commission's actions unilaterally modifying the terms of the 1999 APS Settlement. To the extent that intervenor witnesses have made similar claims, my Rebuttal Testimony will address such claims as well. In addition, I discuss the commitment of Pinnacle West Energy Corporation's ("PWEC") Arizona-based generation to serving our retail customers, both historically and in the future and the potential consequences to those customers should the Commission once again reject the proposal to acquire that generation at cost-of-service regulated pricing. In these latter two respects, I hope to place our actions and concerns into their proper historical perspective and in the context of the broader wholesale electric market.

II. SUMMARY

Q. COULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. APS and its affiliates have diligently adhered to both the letter and the "spirit" of the Commission's Electric Competition Rules, even though many of those rules have been found to be unlawful by two different courts. The Company has similarly complied with the 1999 APS Settlement Agreement and the Code of Conduct approved by this Commission in February 2000. More specifically, we did not mislead any rating agency or, for that matter, anyone else, about either the substance or the status of potential contractual relations between APS, Pinnacle West and PWEC. Those relations, should they ever have been implemented as contemplated in early 2001, which they were not, would have been fully consistent with A.A.C. R14-2-1606(B), the Competition Rule addressing post-divestiture power acquisition by APS, assuming also that the requirements of this rule had ever become operative, which they did not.

PWEC constructed new generation in Arizona to provide APS with, in effect, a reliability "life-line" against the potential for a breakdown in the wholesale electric market. And that decision paid off big time for our customers as the wholesale market suffered an even worse than feared blowout in 2000-2001. But for the knowledge that significant new generation was coming on line beginning in 2001 – generation controlled by an affiliate of the Company and which had been committed by the highest officials of Pinnacle West, including myself, to be available for APS – there is every reason to believe we would have gone down the same road as California, Nevada, and the Pacific Northwest, this is, stampeded into uneconomic long-term contracts. To now suggest either that APS could have continued to construct new generation for native load despite the Commission's then policy on divestiture or, alternatively, that PWEC's doing so was somehow "anti-competitive" is both internally inconsistent and, speaking as one (along with Steve Wheeler) of the active participants in the whole electric restructuring process in Arizona, does not square with the then-existing facts. APS witnesses Wheeler, Ed Fox and Don Robinson will address the two remaining "preliminary inquiry" issues of the air permitting process at West Phoenix and Saguaro and the transfer of surplus APS land to PWEC at those same sites, while Don Brandt, our CFO, and Steve Fetter, a former regulator and ratings agency executive, provide further insight on the same ratings agency presentation issue as is discussed in my Rebuttal Testimony.

Although Mr. Wheeler and Mr. Robinson also discuss in their rebuttal testimonies how APS itself was harmed by the failure of the Commission to fully implement the terms of the 1999 Settlement, I will address the most fundamental and, at least on a prospective basis, most serious of those harms – the continued bifurcation of generation assets as between APS and PWEC and the need to unify those Arizona assets at APS. Simply put, PWEC was not only created as a direct result of, but would never have existed absent the divestiture provisions in the Commission's Electric Competition Rules (which up until the 1999 APS Settlement, the Company had challenged as unlawful) and the 1999 APS Settlement, which APS entered into to comply with such Rules. I know this last statement to be true, not because of a press release or somebody's testimony, but because I was one of the people involved in PWEC's creation in 1999. Its two primary and directly interrelated purposes were: (1) to receive the APS generation units divested under the requirements imposed by such Rules and Settlement; and (2) to construct new generation for APS customers so that these customers would not be wholly dependent on the vagaries of the wholesale electric market for reliable and reasonably-priced generation. In such role, PWEC could also serve as a competitive check on that wholesale market to the long-term benefit of APS and its customers. With the entry of the Track A Order, that new generation, which was intended to be an incremental addition to largely coal and nuclear generation, was effectively and prejudicially "stranded" at PWEC. Thus, rather than having a large fuel-diverse portfolio of profitable generation assets on which to base a viable business plan, PWEC is relegated to a sub-optimal group of all-gas fired generating units, none of which it would have constructed absent the requirement of divestiture. Moreover, this continued bifurcation of our generation into separate companies operating under separate financing and regulatory regimes is a situation that creates ongoing inefficiencies that adversely affect both APS customers and the financial health of the entire enterprise.

Just as it would have been imprudent for APS to have left itself and its customers unprotected after 1999 against wholesale market failures, I believe the Company's impending exposure to such a market carries with it similar risks. By the time the present Track B power contracts expire, APS will have a projected supply deficit of well over 3000 MW and growing. Even with the PWEC assets, that deficit will be some 1400 MW. A deficit of 3000 MW represents 37% of anticipated 2007 peak load. Given that the PWEC assets represent an economic resource addition to the existing portfolio of APS resources and provide the operational benefits of utility ownership, the value of having this additional capacity long-term on a cost-of-service basis is evident from the record in these proceedings.

III. THE PRELIMINARY INQUIRY

Q. WHAT ISSUES DID MS. JARESS DISCUSS RELATIVE TO THE "PRELIMINARY INQUIRY"?

A. Although at one point in her testimony Ms. Jaress references five issues (Jaress Testimony at 12) as being raised by Decision No. 65796, Ms. Jaress then goes on to identify and discuss six issues:

1) PWEC's representations to bond rating agencies;

2) APS' direct or indirect contract with its generation affiliate;

3) PWEC's construction of generation to serve APS;

4) APS' ability to construct new generation under the Electric Competition Rules;

5) APS' application to amend its air permits at West Phoenix and Saguaro to allow the operation of PWEC's West Phoenix CC-4 and CC-5 units, as well as Saguaro CT-3; and,

6) The transfer by APS to PWEC of surplus land at the West Phoenix site at book value.

Although some of the issues, especially what Ms. Jaress characterizes as Issue Nos. 1 and 2, have significant overlap, I will use the same structure and terminology in my Rebuttal Testimony as did Ms. Jaress to describe each of her Issues Nos. 1 – 4. Mr. Brandt and Mr. Fetter likewise will rebut Ms. Jaress' interpretation of the source and significance of PWEC's contingent credit rating, which was in part the result of the ratings agency presentation referenced above. Mr. Wheeler also addresses Issue No. 4. And, as noted in my Summary, Mr. Fox will respond to Issue No. 5, and Mr. Robinson and Mr. Wheeler will respond to Issue No. 6.

Q. WILL THIS BE THE FIRST TIME APS HAS RESPONDED TO THESE ISSUES?

A. No. At Staff's request, APS submitted an over sixty-page point-by-point analysis, both legal and factual, on June 13, 2003 of the specific affiliate transactions and other issues raised by Decision No. 65796. Yet, Ms. Jaress does not refer to, let alone dispute, any of that analysis or even acknowledge its existence in her testimony. Therefore, I have attached our June 13th filing as Appendix B to my Rebuttal Testimony.

Q. IN VIEW OF MS. JARESS' CONCLUSION THAT APS CUSTOMERS SUFFERED NO HARM AS A RESULT OF ANY OF THE COMPANY'S ACTIONS, REAL OR IMAGINED, WITH REGARD TO PINNACLE WEST AND/OR PWEC, WHY ARE YOU AND OTHER COMPANY WITNESSES RESPONDING TO HER TESTIMONY CONCERNING THE "PRELIMINARY INQUIRY"?

A. APS is justifiably proud of its reputation as an honest and ethical corporate citizen. That was why it refused to pay even token penalties during FERC's recent investigation into Western electric markets and instead undertook the painstaking effort to assemble the contemporaneous evidence needed to prove its complete innocence, thus obtaining an unqualified dismissal by FERC of all allegations against APS and its affiliates. APS is equally proud of its efforts to honor its commitments under the 1999 Settlement even though the Company has received significantly less than what it bargained for in that Settlement and what it did receive turned out to be of little value. As to the Code of Conduct and the Electric Competition Rules, APS has either followed these provisions to the letter and beyond or has sought appropriate waivers from this Commission. Indeed, it is our efforts to be 100% compliant with the 1999 APS Settlement's and the Electric Competition Rules' divestiture requirements that has directly led to our present situation. Thus, I look forward to this opportunity to set the record straight and clear our name from under this cloud of suspicion and innuendo.

I also have a personal interest in this issue. I helped negotiate the 1999 Settlement and was one of the Company's chief spokesmen during the Commission's long consideration and adoption of the Electric Competition Rules. Further, Bill Post (Pinnacle West's CEO) and I were the persons who "dedicated" the PWEC generation to protect APS and its customers and prevented any straying from that commitment even when it appeared highly profitable, from an enterprise perspective, to do so. Finally, I personally participated in reviewing the rating agency presentations discussed in Ms. Jaress' testimony before such presentations were made.

I know it was always our intent and goal to meet all of this Commission's expectations concerning electric restructuring while still carrying out our duty to act in the interests of our customers within whatever parameters the Commission had established. I believe we have done precisely that and do not accept the notion that either I have been mistaken about the nature, purpose and value of everything we have done in that regard over the past five years or, worse yet, that I have intentionally misled this Commission, Staff or the financial community about the nature and purpose of our actions.

A. Rating Agency Presentation in February 2001

Q. DO YOU AGREE THAT "AN APS COMMITMENT TO PURCHASE EITHER DIRECTLY OR INDIRECTLY, THE FULL OUTPUT OF THE PWEC PLANTS FOR FOUR YEARS ENDING DECEMBER 31, 2004 . . . GAVE THE PWCC ENTITIES AN UNFAIR COMPETITIVE ADVANTAGE" (JARESS TESTIMONY AT 13)?

A. No. Such a conclusion is both illogical based on the draft agreements themselves and based on several mistaken assumptions. First, these were, by Ms. Jaress' own admission, only <u>draft</u> agreements. How a draft agreement can give anyone a competitive advantage, fair or unfair, is not explained by Ms. Jaress. But even if they had been final, executed documents, they did not commit <u>APS</u> to purchase so much as a single kWh from PWEC. Moreover, Pinnacle West Marketing & Trading was under no restrictions as to how and from whom it would acquire power to fulfill what would have been its obligations to APS under the agreement. Neither was Pinnacle West Marketing & Trading limited to securing power for APS. It could and did serve other wholesale customers from non-APS or non-PWEC resources, and M&T engaged in merchant trading transactions unrelated to either APS or PWEC generation.

I must further add that for at least one of those four years (2001), PWEC could not have anticipated owning significant generation (and thus would have had little to sell to anyone) because divestiture would not have yet occurred and PWEC's new generation expected on line in 2001 consisted only of West Phoenix CC-4 and the temporary generation at West Phoenix and Saguaro. For a second of those four years (2002), PWEC would have not yet received the Company's interest in Palo Verde (which accounts for some 33% of the total energy used by APS). And during the <u>entire</u> four-year term, the draft agreement between APS and Pinnacle West Marketing & Trading would have <u>expressly allowed APS to secure any or all of its needs from third-parties</u>. Finally, even <u>if</u> Pinnacle West Marketing & Trading acquired from PWEC all of the power it would have been obligated to furnish APS, this would have been significantly less than the "full output of the PWEC plants," as contended by Ms. Jaress.

Q. DID PINNACLE WEST, PWEC OR APS EVER REPRESENT TO ANY RATING AGENCY OR ANYONE ELSE THAT THE AGREEMENTS DRAFTED IN LATE 2000 OR EARLY 2001 THAT ARE THE SUBJECT OF MS. JARESS' TESTIMONY HAD BEEN EXECUTED OR WERE OTHERWISE EFFECTIVE?

A. No. The mere fact that at the time (February of 2001), PWEC had no generation, combined with the use of the term "draft" to describe the documents and the lack of any signatures would have signaled that at most they represented one of a number of potential business plans involving PWEC. But to make sure, PWEC and Pinnacle West officials also specifically indicated as much during the presentation itself. I know these things for a fact because I personally reviewed the appropriate slides, charts or documents used in that presentation.

Q. WOULD THE DRAFT AGREEMENT BETWEEN PINNACLE WEST MARKETING & TRADING AND PWEC, IF IMPLEMENTED, HAVE GIVEN PWEC A COMPETITIVE ADVANTAGE?

A. No. The draft Pinnacle West Marketing & Trading agreement with PWEC was essentially a cost-of-service contract tied to generating unit availability and performance. In that sense, PWEC would be indifferent as to whom Pinnacle West Marketing & Trading sold the PWEC power because PWEC would receive the same compensation irrespective of the ultimate buyer. To the extent market prices were above or below PWEC's anticipated cost-of-service, the profits/losses would be realized by Pinnacle West Marketing & Trading and not PWEC. Although this structure was different than that originally conceived at the time of the Settlement, it was both necessary and practical. The Company's power marketing and trading business was to be divested under the Settlement and using Pinnacle West for this function became necessary because, aside from APS, only Pinnacle West had sufficient credit resources to conduct these activities, at least until after divestiture of the APS generation to PWEC. This arrangement also permitted PWEC to concentrate solely on planning, building and operating generation in the most efficient manner possible while the trading and marketing people bore the responsibility to prudently manage and market the combined generation portfolio, including undertaking prudent hedging activities. But given the fact that in early 2001, market prices were far above any plausible projection of PWEC's costs, the rating agencies should have viewed this potential arrangement as a potential negative for PWEC and a positive for APS, with the overall impact on Pinnacle West being neutral.

On the other hand, since the rating agencies' analyses of PWEC's future earning potential encompassed at least 20 years and the credit rating was not final in any event, it is likely that the first four years, two of which had PWEC owning significantly less generation than it would have had for the remainder of the time period under consideration, did not materially affect the result irrespective of whatever assumptions they made about the likelihood that the specific business model represented by the draft agreements would ever be implemented. What would and did make <u>the</u> critical difference to a rating agency is the anticipated divestiture of APS generation to PWEC, which as I discuss later, was also <u>the</u> critical economic assumption underpinning our generation business plan and was the explicit "contingency" attached by the rating agencies to PWEC's contingent credit ratings.

B. APS' Direct or Indirect Contract With its Generating Affiliate

Q. DID APS ENTER INTO ANY POWER AGREEMENTS WITH "ITS GENERATING AFFILIATE" PRIOR TO THE TRACK A DECISION?

A. No, although Ms. Jaress' testimony indicates that she may believe such a contract did exist (Jaress Testimony at 15-16). All PWEC power went to Pinnacle West Marketing & Trading prior to that organization being returned to APS early in 2003, although much of that power was used by APS when it was otherwise economic compared with either APS generation or market alternatives. But even those transactions that did take place between PWEC and Pinnacle West were not done pursuant to the draft agreement referenced in Ms. Jaress' testimony but rather pursuant to other agreements under PWEC's market-based FERC tariff, that although provided to Staff during the discovery, are not discussed in Ms. Jaress' testimony. And, of course, neither the Settlement nor the Electric Competition Rules imposed any restrictions on or even address Pinnacle West's dealings with non-APS affiliates, including PWEC.

Thus, the more appropriate phrasing of this issue by Ms. Jaress is whether the draft agreement between Pinnacle West Marketing & Trading and APS, if implemented, would somehow have violated Rule 1606(B). And although it is difficult to see how APS can be found "guilty" of "attempting" to violate a Rule that never became effective for APS, the Rule having been suspended by the Track A Order prior to its amended (by the 1999 Settlement) effective date of January 1, 2003, the answer to this completely hypothetical question is still a resounding "no."

Q. PLEASE EXPLAIN.

A. The draft APS contract with Pinnacle West Marketing & Trading called for all power sold to APS to be at a derived "market price" under terms of Marketing & Trading's FERC-approved market-based tariff. But, as I previously discussed, any or all of the power acquired by APS for APS retail customers could, under terms of the draft agreement, also be procured through a competitive bidding process. Now if this sounds like exactly the procurement regime envisioned by Rule 1606(B), it's because it is.

Rather than recognize that the result of this agreement, had it ever gone into effect, was exactly as called for under the Rule, if <u>it</u> (the Rule) had ever become operative prior to its being stayed, Ms. Jaress chooses to become unduly fixated on the phrase "arms length." Interestingly, neither the Commission's general affiliate rules (A.A.C. R14-2-801, *et seq.*) nor its specific Electric Competition Rule on Code of Conduct use, let alone define, the term "arms length." When asked during discovery, Ms. Jaress cited no Commission pronouncement as to what the term means either as a general proposition or in its specific application to Rule 1606(B). But, because an affiliated power sales transaction under a FERC-approved tariff at market price was explicitly permitted under the Company's Commission-approved and Staff-written Code of Conduct, which Code of Conduct post-dated both the passage of Rule 1606(B) and the 1999 APS Settlement, there would be no reason for APS to believe that such an inter-affiliate pricing mechanism would not be permitted under Rule 1606(B).

Q. WOULD THE PINNACLE WEST/APS AGREEMENT YOU HAVE DESCRIBED HAVE "DIMINISHED COMPETITION AND, IN THE EXTREME, DRIVEN PWEC'S COMPETITION OUT OF BUSINESS" (JARESS TESTIMONY AT 21, LINES 12-13)?

A. Of course not, and Ms. Jaress provides not even anecdotal evidence (much less any compelling market analysis) to support this claim. Indeed, her statement goes beyond mere hyperbole. As I discuss later in my Rebuttal Testimony, the impact of APS and APS' needs on the wholesale market are itself insignificant compared to that of, say, California. Moreover, since both the size of the market and the total generation available to serve that market would, under Ms. Jaress' interpretation of the draft agreement, have been reduced by the same amount, there would have been no impact on PWEC's competitors – a point also made by Dr. Hieronymus in his Rebuttal Testimony.

C. PWEC's Construction of Generation to Serve APS

Q. WHAT IS THE ISSUE HERE?

A. I'm not sure. Staff witness Harvey Salgo indicates that he doesn't believe that the PWEC assets were constructed to serve APS (Salgo Testimony at 6). Ms. Jaress devotes a significant portion of this section of her testimony to quotes from Company officials which she believes contradict the notion of "dedication" (Jaress Testimony at 22-25). Thus, it is not clear whether it is PWEC's dedication of assets to serve APS or the alleged lack of such dedication that Staff finds to violate "the spirit if not the letter of the Retail Electric Competition Rules ...." (Jaress Testimony at 11). That it may be the former can be adduced by Ms. Jaress' statement that "[I]f PWEC built the plants only to serve APS, it must have been supremely confident that it could win the competitive bid required by R14-2-1606(B) and the Addendum to the 1999 Settlement Agreement or believed it could somehow circumvent the requirement" (Jaress Testimony at 22, emphasis supplied).

Putting aside the fact that neither APS nor PWEC has ever asserted that the plants were built only to serve APS, in the sense that it was always intended that these new PWEC units would make the same sort of off-system sales as did and still do the existing APS generating plants, thus reducing this to a "straw-man" argument discussed later in my Rebuttal Testimony, the answer to Ms. Jaress' implicit question is that, "yes," PWEC was exactly so "supremely confident," and with good reason. Every study conducted showed that PWEC's combination of divested APS generation and its newly-constructed generation would be able to operate at a lower cost than any likely market competitors, thus allowing PWEC to economically serve as much of APS load as it chose to serve at whatever the competitive market clearing price turned out to be. Yet an additional explanation of PWEC's actions was the desire of Pinnacle West management, and more specifically myself, to protect APS and its customers from the potential for market failure if the wholesale market did not develop early enough and fully enough to assure APS of reasonably-priced and reliable sources of power.

The first of PWEC's business assumptions, that it would have a portfolio of fuel-diverse assets with which to compete for APS load, was eventually frustrated by the Track A Order. But, PWEC's role as a market hedge for APS has turned out to be even more important than might have reasonably been anticipated back in

1999, and PWEC's Arizona generation can continue to serve that function for decades to come under the Company's rate base proposal.

Q. WHY WOULD PWEC HAVE BEEN WILLING TO COMMIT ITS GENERATION, INCLUDING THAT TO BE RECEIVED FROM APS, TO SERVING APS AND WHY WOULD APS BENEFIT FROM SUCH A COMMITMENT?

A. Although sometimes forgotten, given the much larger electric market melt-down of the following year, there were severe, but more localized and of greatly shorter duration, power market blow-outs in the Midwest during 1998 and the late spring of 1999. The price of power reached thousands of dollars per MWh. Both customers and utilities in the region were placed under significant financial strain. As was later the case in California, no one, including APS, had predicted either the timing or magnitude of this market disruption, but APS had believed since the beginning of Arizona's restructuring effort that leaving its customers "uncovered" in a developing and still immature wholesale market would sooner or later lead to a calamity for both them and the Company. And, of course, the rest is history if you are a customer of one of those unfortunate utilities in California, Nevada or the Pacific Northwest that found themselves in precisely that position.

Q. WHAT STEPS WERE TAKEN TO COVER THE APS SHORT POSITION?

A. Even at the time the 1999 APS Settlement was finalized in May of 1999, APS was nearly 1200 MW short to the market and getting shorter. To meet the Company's growing electric load and ensure reliable service to our customers, we implemented a two-pronged strategy. First, Marketing & Trading entered into a series of hedging arrangements (both financial and physical) to manage wholesale electric and natural gas price and reliability risk until new generation could be brought on line as a long-term solution. Second, PWEC proceeded to implement that longer-term plan by initiating and completing the construction program that resulted in the PWEC Arizona generation. Because this long-term strategy was already in the works and even partially implemented by 2001, we did not have to panic or negotiate with merchant suppliers from the same position of weakness as did utilities in California, Nevada, and the Pacific Northwest, which like APS were caught short but unlike APS, did not see any "steel in the ground" help coming and thus were forced to cut the best deal they could. Those deals which turned out not to be much of a deal at all. I firmly believe that events have proven the value to our customers of resource planning based on a firm foundation of asset-backed and utility-owned resources. This is also, in my opinion, the same conclusion to which this Commission came in entering the Track A Order.

Q. WHAT ABOUT THE SO-CALLED INCONSISTENT STATEMENTS MADE BY OTHER COMPANY OFFICIALS?

A. It is not clear how this is connected with the Rule 1606(B) issue or whether Staff believes that making seemingly inconsistent statements is itself a violation of the "spirit if not the letter" of something or other. Fortunately, there is no inconsistency, and thus there is no need for further speculation over what, if any, point Staff is attempting to make relative to the "preliminary inquiry."

Much is made by Staff and others over the use of the word "merchant" by Mr. Fox or Mr. Bill Stewart (former President of PWEC), to describe one or more of PWEC's plants. Yet, that term only denotes a power plant that was not constructed, acquired or operated by an electric utility as a regulated asset. Thus, the generation PWEC was to receive from APS under the 1999 APS Settlement would likewise have been considered "merchant" generation post-divestiture. PWEC could have used the terms "non-utility" or "unregulated" in discussing the plants. It would have told you nothing, in and of itself, about the intended role of the plants, both new and those to be acquired from APS, in serving APS needs. But, whatever word you pick does not detract from the simple truth that APS could rely on all of PWEC's capacity and energy to economically and reliably serve the Company's customers. Nor does it negate PWEC's words and actions that were not only consistent with the concept of "dedication," but frankly inexplicable in the absence of such concept.

Q. WHAT WORDS AND ACTIONS OF PWEC ARE YOU TALKING ABOUT?

A. I would first point to the Company's 1999 Long-Range Forecast ("LRF"), which clearly included what later became the PWEC Arizona generation (excepting Saguaro CT-3, which was later added as the permanent replacement for the temporary generation used at Saguaro and West Phoenix in 2001) as part of the resources that would serve future APS needs. The Loads and Resources section of the 1999 LRF is attached to my Rebuttal Testimony as Schedule JED-1RB. I would also note the "Generation Marketing Plan" presented in December of 2000. The relevant portion of that Plan is attached as Schedule JED-2RB. This was during the height of the California blow-out and only a few months before California would go on a buying spree that has left it with $30 billion or so in uneconomic long-term contracts. At the very beginning of the presentation, it is crystal clear that the Plan addresses the marketing of what is termed "surplus capacity and energy." And "surplus" is explicitly defined as that not needed to serve APS needs. This is consistent with the quotes cited by Ms. Jaress (Jaress Testimony at 23) from Mr. Post wherein he specifically states "we are committed to meeting the growing needs of our customers. . ." and "we have sized our generation expansion plan, when you combine that with our existing generation, to what we think the native load will be . . ." (Jaress Testimony at 24). A similar statement was made by Mr. Post in the 2000 Pinnacle West Annual Report.

In the months that followed, Marketing & Trading employees continued to monitor the Western market to determine whether some of the anticipated PWEC power could safely be "sold forward" to California for the considerable profits to be made by those sales. They told me that the power could later be replaced at lower prices with minimal risk to APS and its customers. But as I saw the California utilities and others in similar circumstances throughout the West plunging into an ever-deepening financial crisis, one which I knew would sooner or later saddle their customers with much higher costs, I determined that even a "minimal risk" that our customers would end up in the same predicament was not a risk they should bear or that APS was prepared to accept. So I told them no, the PWEC assets were our customers' insurance policy, and I didn't intend to take out any loans against that policy.

Finally, I must remind the Commission of another fact, which was discussed in Mr. Bhatti's Direct Testimony at pages 17, 56 and 68. The construction schedule for Redhawk Units 1 and 2 was accelerated to meet APS demand growth, despite PWEC's analysis that it would be more profitable for PWEC (but more expensive for APS, even aside from reliability concerns) to wait until closer to the next "boom" in the "boom/bust" cycle discussed by both Mr. Bhatti (Bhatti Direct Testimony at 21) and Dr. Hieronymus (Hieronymus Direct Testimony at 54-63).

Q. DID RULE 1606(B) OR THE 1999 APS SETTLEMENT REQUIRE THAT APS BE COMPLETELY EXPOSED TO SPOT MARKET PRICES STARTING IN 2003?

A. No, although there is language in both Decision No. 65976 and Ms. Jaress' testimony that could be read or misinterpreted to suggest such an obviously undesirable result. Rule 1606(B) was intended to govern the Company's acquisition of power post-divestiture. There is nothing in either the letter or spirit of that Rule that prohibits APS from having a plan if the wholesale competitive market failed, as we all know now it did. And under the draft agreements discussed in Ms. Jaress' testimony, APS had no legal obligation to purchase power from PWEC because it would have been free to contract with third-parties, either directly or through Marketing & Trading. Thus, PWEC was, in effect, giving APS a free hedge against what proved to be a runaway market.

Q. WHAT DO YOU MEAN "FREE HEDGE"?

A. Under the draft agreements discussed by Ms. Jaress, PWEC assets (if physically operable) would have had to have been made available to serve APS, through Pinnacle West Marketing & Trading, if and when and to the extent called upon by APS. Yet under those same draft agreements, APS would have owed <u>nothing</u> unless and until it did call on PWEC's generation and would have been under <u>no</u> obligation to ever call on PWEC's generation if the Company could have procured lower cost power elsewhere.

Q. DID THAT HEDGE PROVE NECESSSARY?

A. Absolutely. Without the trailer-mounted temporary generation installed by PWEC in 2001 (replaced in part the following year by the construction of Saguaro CT-3), along with the rapid construction that same year of West Phoenix CC-4, APS could not have met its load in 2001. These actions alone cost PWEC at least $120 million (Bhatti Direct Testimony at 57). And without the knowledge that Redhawk would be completed in time for the following summer (with West Phoenix CC-5 coming on line in 2003), there is every reason to believe that APS would have ended up like California and Nevada – having to buy into a sellers' market.

It also became evident to APS in 2001 that the problems with the wholesale market were not just temporary and thus a long-term alternative to the requirements of Rule 1606(B) would better serve APS customers. Thus, we came to the Commission with a proposal that would have provided APS customers with cost-of-service prices from PWEC generation while still allowing the Commission's original vision of divestiture to take place. And, ironically, that same proposal may have provided for more power to be acquired by APS from the competitive market than was subsequently procured under the Track B Order. When the Commission instead determined that, while agreeing with APS that Rule 1606(B) was deficient, it also wished to change its vision back to that of a vertically-integrated utility, APS and PWEC found themselves in the present dilemma.

Q. WERE THE COMMISSION AND COMMISSION STAFF AWARE THAT PWEC GENERATION WAS GOING TO BE COMMITTED TO SERVE APS LOAD?

A. Yes. In the "Summer Preparedness" presentation to the Commission during February of 2001, we clearly identified the PWEC generation coming on line during those and future years as a vital component of the generation needed to serve the anticipated APS load. Attached as Schedule JED-3RB is a slide from that presentation, which was attended by several of the Commissioners and Staff. Also, a FERC Commissioner, the Secretary of Energy and the Governor held meetings in Arizona to discuss the then-ongoing Western energy situation. The use by APS of the new generation provided or to be provided by PWEC was discussed during each of those meetings, some of which were also attended by at least one of Arizona's Commissioners. And finally, the 2000 Pinnacle West Annual Report (which was certainly available to the Commission and Staff) indicated, after a discussion of the Company's strong growth in retail demand and the need to construct the infrastructure necessary to meet that demand: "[O]n the generation side, we're meeting new demand growth through our unregulated subsidiary, Pinnacle West Energy." 2000 Pinnacle West Annual Report at 2. At no time during those years did either Staff or the Commission indicate that APS could not or should not rely on PWEC's "merchant generation" because of Rule 1606 (B) or that to do so was somehow a violation of the 1999 Settlement.

Q. DIDN'T THE PWEC ASSETS ALSO INTEND TO PROVIDE POWER TO NON-APS CUSTOMERS?

A. Yes, as did the APS assets that were to be transferred to PWEC and as would the PWEC assets if they are acquired and rate-based by APS. The ability of any generation to produce margins from off-system sales when either not needed or not economical to run for native load customers is an inextricable aspect of modern power plant economics. It no more negates the concept of "dedication" than would renting out one's home to some desperate fan during the Fiesta Bowl weekend indicate a desire to permanently move. Moreover, as is also discussed in Dr. Hieronymus' Direct and Rebuttal Testimony, PWEC did pursue generation opportunities (largely outside Arizona) that did not conflict with but were not necessarily a part of its two primary functions of being the home for APS' divested generation and building sufficient new generation to protect APS and its customers. Once again, this no more undermines PWEC's dedication to APS than taking up a second job necessarily undermines one's dedication to his or her first job.

D. APS Construction of Generation

Q. DOES STAFF WITNESS JARESS TESTIFY THAT APS COULD CONTINUE TO BUILD OR ACQUIRE GENERATING PLANTS TO SERVE ITS CUSTOMERS PRIOR TO JANUARY 1, 2003?

A. Ms. Jaress seems to be of two minds on the subject. At one point, she seems to say APS could construct plants – it just couldn't use them to provide generation to customers (Jaress Testimony at 26). Yet one page later, she indicates that APS could have come to the Commission and asked for a waiver (Jaress Testimony at 27). I find neither of these alternatives to be consistent with either the 1999 APS Settlement or the Electric Competition Rules. Indeed, if just days after the 1999 APS Settlement was approved, APS had filed for a Certificate of Environmental Compatibility ("CEC") to construct new generation (e.g., Redhawk) that would then have to be divested to PWEC within six months of completion or had asked this Commission for authority to borrow the $750 million needed for such construction on APS credit, I'm sure that would have been viewed, justly in my opinion, as violating "the spirit, if not the letter" of both the 1999 APS Settlement and the Electric Competition Rules. After all, the last time APS filed for a significant waiver of the Electric Competition Rules, which was to the "market price" and "50 % competitive bidding" provisions of then Rule 1606 (B), the Company was exactly so-accused of violating the 1999 APS Settlement for even asking, and it never received a hearing on its request. And I cannot help but note that Staff witness Salgo appears less certain than Ms. Jaress that APS <u>can</u> acquire or build new generation (Salgo Testimony at 12 and 25), notwithstanding Ms. Jaress' testimony and notwithstanding the intervening issuance of the Commission's Track A Order.

Q. IF YOU BELIEVED APS HAD THE CONTINUED ABILITY TO CONSTRUCT OR ACQUIRE GENERATION PRIOR TO 2003, WOULD THE PWEC GENERATION HAVE BEEN CONSTRUCTED BY APS RATHER THAN PWEC?

A. Not if APS was still under the obligation to divest its generation by January 1, 2003. But if by your question you mean to ask whether APS would have constructed the PWEC Arizona generation had it never been subject to what proved to be an unlawful requirement that it divest its generation, the answer is an unqualified "yes." The planned need for and economics of the PWEC generation did not depend on which entity built it. Thus, as is discussed more fully in Mr. Wheeler's and Dr. Hieronymus' rebuttal testimonies, it is unreasonable to apply a different rate making standard to the PWEC generation than has historically been applied to other generation constructed by APS.

IV. UNIFICATION

Q. WOULD YOU EXPLAIN THE BIFURCATION ISSUE TO WHICH YOU ALLUDED IN YOUR SUMMMARY?

A. Yes, although I would like to place my emphasis on the advantages of unification rather than the disadvantages of bifurcation. As I discuss in the next section of my Rebuttal Testimony, APS is a relatively small fish in a mighty big ocean. We knew that it would be difficult if not impossible to compete in the wholesale market as a "start up" generator against huge firms (and members of the ACPA) such as Sempra, Duke, Calpine, NEG, Reliant, etc. Thus, from the very beginning our business plan called for keeping all the enterprises generation as part of a single portfolio, whether that was at APS, as we had argued from the initial consideration by the Commission of the Electric Competition Rules in 1996 through the 1999 Settlement, or at PWEC, which was created in response to the 1999 Settlement. Our studies had shown that all of APS' then existing coal and gas-fired generation was already very competitive, and even the nuclear generation would produce positive cash flows. And although the new gas-fired generation then contemplated to be constructed by PWEC would earn competitive rates of return over their useful life, we realized and anticipated that during the first few years of operation, PWEC would need the cash flows expected from receipt of the existing and older APS generation to survive as a stand-alone entity. With the halt to divestiture, the two halves of what was intended to be a single generation portfolio are now divided into sub-optimal components of separate entities.

Q. IS THIS THE SAME ISSUE AS THE DEDICATION OF THE PWEC ASSETS TO APS?

A. No. Even if the Commission does not find that PWEC constructed its Arizona plants to serve APS or does not find that relevant even if it did, there can be no debate about the fact that but for the promise and requirement of divestiture, PWEC and the PWEC assets would not exist. They either would have been built by APS, if that were allowed by the Commission, or they would not exist at all. In either instance, the unification issue also would not exist. The equities here are especially strong because it appears in hindsight that the Commission lacked legal authority to compel divestiture, which Commission requirement is why we are in this situation today.

Q. DIDN'T THE COMMISSION'S APPROVAL OF THE COMPANY'S TWO FINANCING APPLICATIONS IN LATE 2002 AND EARLY 2003 SOLVE THIS BIFURCATION ISSUE?

A. No. They simply allowed Pinnacle West to survive as a credit-worthy enterprise <u>until</u> the Commission had the opportunity to address the underlying issue of unification, which was first raised by our Chairman, Mr. Post, in his July 11, 2002 letter to the Commission in the Track A proceeding. And in conjunction with these financing proceedings, Staff and APS recognized in the Principles of Resolution that this rate proceeding was the appropriate forum to seek solutions for this problem.

Q. OTHER THAN THE ISSUE OF REFINANCING THE PWEC-RELATED DEBT INCURRED BY PINNACLE WEST, DOES THE LACK OF UNIFICATION CREATE OTHER PROBLEMS FOR APS AND ITS AFFILIATES?

A. Yes. And the financing issue is itself a terribly significant "other than" problem for the enterprise. But just from the standpoint of operations, the inability to jointly dispatch the APS and PWEC generation for native load (except during the months of the Track B contract) also costs APS (and eventually its customers) millions of dollars a year. This is because maintaining separate dispatch "stacks," that is, one for PWEC and another for APS, is simply less efficient than using a single "stack" for both native load and off-system sales.

For example, in 2005 alone, it has been estimated that this division of resources will cause APS to incur an additional $14.7 million in costs. And because each entity must provide its own separate reserves for any firm sales, rather than being able to firm up each other, joint marketing opportunities are either lost or produce lower margins – margins that help to offset the costs of fuel and purchased power for APS customers. Again, for 2005, these reduced margins are estimated to cost APS and its customers some $5.7 million. Although this is partially offset by PWEC margins, the net loss of efficiency in 2005 to the two entities would be over $14 million.

From a management perspective, the need for duplicative management structures is both inefficient and harmful to proper corporate governance and oversight – something I believe we can all agree is critical in this industry. This problem is exacerbated by the restrictions imposed by the Track B and financing decisions, which effectively place PWEC at a disadvantage relative to its competitors. Such restrictions include the special requirements for affiliate bilateral agreements in the Secondary Procurement Protocol (required by the Track B Order) and the limitations on PWEC's ability to acquire or dispose of assets (imposed by the second financing order). These restrictions are themselves contrary to the terms of the 1999 APS Settlement, wherein it had been promised that PWEC would not be under regulatory provisions not otherwise imposed on merchant generators.

V. <u>THE WESTERN WHOLESALE MARKET</u>

Q. IS THERE A DISTINCT "ARIZONA" WHOLESALE ELECTRIC MARKET?

A. No, despite the off-hand reference to such in various witnesses' testimony (Salgo Testimony at 15; Kalt Testimony at 36) and perhaps even in statements made by the Company. There are individual wholesale electric buyers and sellers located in Arizona, but they buy from and sell into what is at least a regional wholesale electric market.

Q. WHAT IS THE EXTENT OF THAT REGIONAL MARKET?

A. At a minimum, you are talking about the entire WECC. That encompasses some 170,000 MW of generation in 14 states and Western Canada. Of that, approximately 66,000 MW is either located in California or owned/controlled by California-based load serving entities. APS and PWEC together comprise only 3.5% of that market, and the energy used by APS customers comprises just 3.2% of the energy generated in the WECC during 2002. The annual growth of energy consumption and demand in the WECC is itself equal to over 14,600 GWH and 2540 MW, with 43% of that coming from California even though that state has yet to recover from the energy-induced recession of 2000-2001.

Q. GIVEN THE VAST SIZE OF THE WESTERN MARKET, WERE YOU SURPRISED THAT MANY OF THE PARTICIPANTS IN THAT MARKET EITHER CHOSE NOT TO PARTICIPATE IN THE TRACK B SOLICITATION OR SUBMITTED NON-COMPETITIVE BIDS?

A. Only in the respect that some of these same entities had participated throughout the Track B proceeding and had opposed the 2001 PPA so intensely. That led me to believe that they might have more interest in serving APS than turned out to be the case. Even in this proceeding, none of the merchant intervenors or the ACPA has offered to provide any proof that the APS service area was intended as their primary market despite the Company's request during discovery for such evidence.

Q. WHAT WOULD BE THE IMPACT OF RATE-BASING THE PWEC GENERATION ON THIS WHOLESALE MARKET?

A. As you can see from my foregoing discussion, 1700 MW of either generation or retail load barely constitutes background "noise" to the clatter of regional wholesale electric activity. And because both the load and the generation would continue to exist independent of whether the PWEC assets are acquired by APS, the overall competitive balance within the region is left undisturbed by even this tiny reshuffling of the generation ownership deck. My common sense observations are, in this regard, fully consistent with Dr. Hieronymus' more rigorous analysis of this same issue in his Rebuttal Testimony.

Q. BUT ISN'T INCREASED VERTICAL INTEGRATION BY UTILITIES BAD FOR WHOLESALE COMPETITION?

A. It's neither good nor bad. It is simply how some market participants, or their regulators, choose to structure their business. Nor should vertical integration itself be confused with the exercise of vertical market power, which consists of a vertically-integrated firm using its ownership of "essential" or "bottleneck" facilities, in this instance, transmission, to discriminate against competitors. Dr. Hieronymus addresses this market power issue in his Rebuttal Testimony and, like me, distinguishes that form of market power from the different question of whether greater degrees of vertical integration increase market concentration in a manner likely to materially and adversely impact the wholesale market. It is this latter concern that is reflected in ACPA witness Dr. Joseph Kalt's testimony (Kalt Testimony at 36-38).

But all vertical integration does, from a market concentration perspective, is associate a portfolio of generation resources with a specific load. As also discussed by Dr. Hieronymus, virtually no merchant generation will be constructed for the foreseeable future without having a firm long-term agreement with a load serving entity. Such a PPA ties the generation backing it no less to the buyer's load than would outright ownership, but brings with it counter-party credit and contract performance risks not attendant in the case of generation ownership. The only other differences would be that PPA pricing would not be based on cost and the utility would not enjoy the operational benefits of ownership. These differences may be quite important to the utility and its customers, but they are irrelevant to the impact on the competitive market of either rate-basing an asset or entering into a long-term PPA.

In addition, at least half of the West will remain vertically-integrated in any event barring a political revolution of historical proportions. This is because public power, which controls 40% of transmission and over 40% of generation in the WECC, shows no inclination to surrender the proven economic advantages of vertical integration, and there appears to be no political will in Washington or the states to change that inclination. If you add to that the investor-owned utilities ("IOU") that are likely to remain vertically-integrated as a matter of state regulatory policies – for example, the three large California IOUs, Idaho Power and PacifiCorp – you are well over that 50% figure irrespective of what the rest of the West does, let alone APS.

Q. MR. DAVIS, DOES NOT DR. KALT TESTIFY THAT INCREASING THE COMPANY'S OWNED-GENERATION MAY HAVE "NEGATIVE IMPACTS" ON THE COMPETITIVE WHOLESALE MARKET AND WOULD SEND A SIGNAL TO POTENTIAL INVESTORS IN MERCHANT POWER PROJECTS THAT THERE IS NOT A "LEVEL PLAYING FIELD" BECAUSE OF THE ALLEGATION THAT "OTHER MARKET PARTICIPANTS WILL HAVE BEEN DENIED A FAIR OPPORTUNITY TO COMPETE WITH PWEC" (KALT TESTIMONY AT 32)?

A. That's what the testimony says. But as to these alleged "negative impacts," Dr. Kalt provides no evidence to support his concerns, and given the relative size of this increment of additional APS-owned capacity to the regional market and the total lack of net impact on the region's supply/demand balance, I doubt any such evidence exists. Thus, I find it more than a little hard to believe that future investment decisions on power plant development in Arizona will be curtailed because the PWEC units were rate-based under the particular, even unique circumstances in this case.

More directly to Dr. Kalt's point, "other market participants" have not been "denied a fair opportunity to compete with PWEC." In fact, they have had such opportunities both in Track "B" and during the ongoing 2003 RFP process. But in neither instance have they proposed any transaction that produced net benefits for APS customers compared to the equivalent PWEC proposal. However, Dr. Kalt's clients apparently want to claim a "mulligan" on every shot until they finally can get the ball into the hole.

VI. GROWING APS CUSTOMER EXPOSURE TO MARKET RISK

Q. IF RATE-BASING HAS NO IMPACT ON THE COMPETITIVE MARKET, IS IT STILL IMPORTANT TO APS AND ITS CUSTOMERS?

A. Absolutely. Aside from being necessary to finally resolve the bifurcation issue and the anticipated economic and operational benefits discussed by APS witnesses Wheeler, Hieronymus and Bhatti, the PWEC assets provide a future hedge against market risks not factored into the economic analyses. No one may be out there predicting another California, but then no one predicted the severity of the first one either, and I believe that until we have a fully functional, transparent and sufficiently liquid wholesale market, it is prudent for APS to limit its exposure and that of its customers in that market to manageable levels. The non-PWEC Track B contracts already amount to 600 MW (150 MW during the summer and as high as 450 MW in certain non-summer months). And, of course, that amount would be in addition to the long-term PPAs we already have with PacifiCorp and Salt River Project. These contracts also do not reflect short-term or economy purchases, although as discussed in Mr. Bhatti's Rebuttal Testimony, even increased exposure to the market for economy energy carries with it a not-insignificant risk.

Q. WHEN DO YOU BELIEVE THE MARKET WILL BECOME FULLY FUNCTIONAL, TRANSPARENT AND SUFFICIENTLY LIQUID TO RELY UPON FOR A MUCH LARGER PORTION OF THE COMPANY'S NEEDS?

A. It certainly is not on the near term horizon. First, we have to have significantly more credit-worthy players. For example, at the height of power marketing and trading in the West, APS was able to do business with at least 23 major wholesale trading counterparties. That is down to 12 today. Second, we need more liquidity. Third, we need some agreed-upon and common rules for public and investor-owned power entities. We have made some progress here, but the public/private power situation discussed earlier is still a big impediment to having the common "rules of the road" needed for an efficient market. Fourth, such a market will need continued access to adequate transmission infrastructure and the pricing mechanisms to efficiently allocate that infrastructure. Again, I think APS, this Commission and FERC are trying to address this issue, but we cannot relax on this critical issue. Fifth, there is a need for better financial hedging tools to mitigate the natural fluctuations in any commodity market, fluctuations made worse in the case of power because of its non-storable nature. Unless these structural issues are addressed, the wholesale market, which will always be characterized by chronic price volatility, will be even more and more unpredictably unstable for reasons unrelated to fundamental supply and demand factors. This kind of volatility can be neither eliminated nor adequately mitigated over the long run.

Q. IF ALL OF THESE CONDITIONS WERE MET, WOULD IT BE APPROPRIATE FOR APS TO OBTAIN ALL OR MOST OF ITS CUSTOMERS' POWER NEEDS FROM THE WHOLESALE MARKET RATHER THAN BUILD OF BUY NEW GENERATING PLANTS?

A. No. Even then, I would not believe it appropriate to abandon an asset-backed resource plan for the majority of our customers' needs. Owning generation provides operating flexibility simply not available through a contract. More importantly, perhaps, electric markets, even if made more efficient, would not necessarily be timely. By that, I mean there will always be lags between changes in demand and corresponding changes in supply. It is these lags that cause the "boom/bust" cycles discussed by Mr. Bhatti and Dr. Hieronymus, and which, along with the storage issue I previously mentioned, explain why even the most efficient wholesale market will be comparatively volatile, carrying with it very significant price risk for our customers. In that regard, it is instructive that even with a fully functional, transparent and sufficiently liquid market for natural gas – one which has the added ability to use storage as a hedge - Arizona consumers, including APS, have been rocked by gas price volatility these past months, with little relief in sight.

Q. WHERE DOES APS STAND TODAY WITH REGARD TO MARKET EXPOSURE?

A. Attached as Schedule JED-4RB is a chart showing our growing short position to the market. With the existing Track B contracts, the Company's capacity deficit ranges from just over 100 MW in 2004 to over 1100 MW in 2006. Beginning in 2007, that deficit increases to well over 1400 MW, even assuming the PWEC assets are acquired by APS and that SRP does not cancel its long-standing power agreement with the Company, and climbs by some 300 MW or so per year thereafter. By the end of this decade, this means that APS would be 2420 MW short to the market even after rate-basing the PWEC generation, or some 30% of its then-anticipated retail load. To give that some perspective, APS' entire retail load did not even reach that same 2420 MW figure until 1978–five years after I came to the Company. A utility that is exposed to that extent will have to buy large amounts of power at the margin with corresponding degrees of pricing risk. Perhaps more ominous is the fact that APS would be approaching the same levels of market exposure as have left California and Nevada utilities and their customers in their present state of financial disarray.

Q. BUT MR. DAVIS, WHAT IF, DESPITE THE ANALYSES OF MR. BHATTI AND OTHERS, INCLUDING MR. SALGO AND RUCO WITNESS DAVID SCHLISSEL, SHOWING THE LONG TERM ECONOMICS OF THE PWEC ASSETS, THERE ARE YET OTHER EXPERTS THAT BELIEVE FUTURE MARKET PRICES MAY STAY SUFFICIENTLY LOW SUCH THAT THE PWEC ASSETS ACTUALLY TURN OUT TO BE TO SOME DEGREE UNECONOMIC. DOES THAT MEAN RATE-BASING SUCH ASSETS WOULD BE A BAD DEAL FOR CUSTOMERS?

A. No. First of all, the PWEC assets bring far more benefits than just their ability to protect APS customers from potentially-higher (higher, that is, than anticipated) purchased power costs. There are reliability and operational advantages to owning "steel in the ground," advantages from the unification of the PWEC generation at APS, and advantages to having the additional energy available to generate off-system sales margins for the benefit of native load customers. As is discussed in Dr. Hieronymus' Rebuttal Testimony, don't confuse your homeowner's insurance with the mortgage payment. But even if you just were considering the PWEC units as the economic price hedge alluded to in the question, my answer would still be "no." Just because you don't expect your house to burn down during the term of a fire insurance policy does not mean it is imprudent to insure against the possibility of that occurrence. Neither would it matter if, in fact, the fire did <u>not</u> occur. Thus, even if based on scientific studies concerning the statistical incidence of house fires and using reasonable financial projections, it could be demonstrated that there would be an anticipated net benefit to a homeowner from taking the money which would otherwise go to purchasing insurance and instead saving and investing such funds for, say, the next twenty years, this would not "prove" that fire insurance is either unnecessary or a "bad deal." The whole point of insuring against a risk, the timing, severity and even occurrence of which is unknown is precisely that - it is unknown. In my example, the homeowner doesn't know whether a fire will occur in twenty years or in the next twenty minutes, so a prudent person would still insure against the risk.

Q. IF THE PROBLEM ONLY BECOMES ACCUTE AFTER THE TRACK B CONTRACTS EXPIRE AND WHEN THE PWEC ASSETS WILL OBVIOUSLY BE EVEN MORE VALUABLE, WHY NOT SIMPLY WAIT AND CONSIDER RATE-BASING THEM IN THE NEXT APS RATE PROCEEDING?

A. If the Commission entirely rejects rate-basing the PWEC assets in this proceeding, it would send a clear signal that the Commission believes increasing market dependence is appropriate irrespective of the underlying economic and equitable arguments supporting the Company's rate base proposal. APS will then pursue the next least-costly supply expansion option still available to it, quite possibly one of those plans analyzed by Mr. Bhatti and presented in his Rebuttal Testimony or perhaps some new variant on such plans. The precise option selected will depend both on conditions (existing and anticipated) at the time a decision is made and on this Commission's determination of the resource planning and acquisition issues discussed by Mr. Wheeler in his testimony. However, as President of Pinnacle West, I must also direct PWEC to proceed with a "Plan B" to market its plants in such a manner as best improves PWEC's chances of survival as a viable entity. Whether that entails another future proposal to transfer these particular assets to APS (if such asset acquisition by APS is consistent with the Commission's market structure vision, as determined in this proceeding) or selling power to some other entity will likewise depend on conditions (existing and anticipated) at the time. But PWEC cannot be held to its earlier book value offer or to the concept of "dedication" itself given the fact that there would have twice been cost-of-service proposals presented to and rejected by the Commission.

VII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. They concern each of the four basic subject areas of my Rebuttal Testimony.

First, the allegations made by Staff concerning the "preliminary inquiry" lack substance. In some instances, they concern transactions that never took place while in others they reference matters that do not reflect "transactions" at all, affiliate or otherwise, but rather involve the meaning of certain statements made concerning the role of PWEC or question the Company's firm belief that it would be inconsistent with both the 1999 APS Settlement and the Electric Competition Rules for it to both agree to divestiture and then immediately launch a billion dollar APS generation construction program. In no instance has Staff demonstrated that any of the actions undertaken by APS and its affiliates violated either the letter or spirit of any Commission order or regulation, provided PWEC with any "unfair advantage" or prejudiced any other wholesale market participant. Rather, these actions directly contributed to the success APS achieved in both preserving its own financial integrity and protecting its customers in the face of what this Commission correctly characterized in the Track A Order as a market that is "poorly structured and susceptible to possible malfunction and manipulation" (Decision No. 65154 at Finding of Fact No. 16) and that is "not currently workably competitive" (Decision No. 65154 at Finding of Fact No. 25).

In Decision No. 65154, the Commission also expressed its desire to act fairly with regard to the consequences of its "change of direction" (Decision No, 65154 at page 22). The single most vexing of such consequences to APS and its affiliates is the artificial division of the generating assets built to serve APS customers. This division has frustrated a business plan predicated on the promises of the 1999 APS Settlement and the requirements of the Electric Competition Rules, brought Pinnacle West to the verge of financial collapse and costs APS consumers money, both currently and in terms of potentially foregone opportunity costs, should the Commission not resolve the bifurcation issues by permitting APS to acquire PWEC's Arizona generation and place it under traditional cost-of-service regulation.

APS is a small fish in a large and often dangerous competitive ocean. Although the Company and its needs have little impact on the wholesale market, the wholesale market can have large, unpredictable, and potentially disastrous impacts on APS and its customers. APS' exposure to these impacts will grow in the future even under the Company's current plan. Without the PWEC assets and the right to build or acquire new "steel in the ground," as is discussed by Mr. Wheeler in his Direct and Rebuttal Testimony, that exposure will rise to levels that have portended financial ruin for other electric utilities and much higher rates for their customers.

Q. DOES THAT CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes, it does.

STATEMENT OF WITNESS QUALIFICATIONS

Jack Davis is President and Chief Operating Officer for Pinnacle West Capital Corporation (PWCC) and President and Chief Executive Officer for Arizona Public Service Company (APS). He is also on the Boards of PWCC and APS.

Mr. Davis attended New Mexico State University and received BS degrees in Medical Technology in 1969 and Electrical Engineering in 1973. He was then hired by APS as an Engineer in the System Planning Department. Subsequently, he has had positions as Administrator of Power Contracts, Manager of Power Contracts, Director of System Development and Power Operations, Director of Fossil Generation, Director of Transmission Systems, Vice President of Generation and Transmission, Chief Operating Officer for PWCC, President of PWCC and was promoted to Chief Executive Officer of APS in September of 2002.

He has served (i) as Chairman of the Western Electric Coordinating Council (WECC) and is a member of its Board of Trustees; (ii) as Chairman of the Western Systems Power Pool; (iii) as President of Western Energy and Supply Transmission (WEST) Associates; and (iv) as a past member of the National Electric Reliability Council Board of Trustees. He is a registered Professional Engineer in the State of Arizona. He is also on the Boards of the Greater Phoenix Chamber of Commerce, Arizona Chamber of Commerce where he serves as past Chairman, and presently serves as Chairman of the Arizona Theatre Company. He is a member of the Dean of Engineering Advisory Council at Arizona State University; Electrical Engineering Industry Advisory Committee at Arizona State University; Greater Phoenix Leadership; and the Downtown Phoenix Partnership.

Arizona Public Service Company's Report to the Arizona Corporation Commission

June 13, 2003

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I. EXECUTIVE SUMMARY

This Report to the Arizona Corporation Commission ("Commission") has been prepared in response to Decision No. 65796 (April 4, 2003). That decision directed the Commission's Utilities Division Staff to commence a "preliminary inquiry into APS' and its affiliates' compliance with the Electric Competition Rules, Decision No. 61973, APS' Code of Conduct, and applicable law." Each of these issues is addressed in this Report. In addition, APS will respond to certain specific assertions made during the January 2003 hearing on APS' Financing Application. This Report demonstrates that:

- APS and its affiliates have, within the regulatory constraints placed upon them, consistently acted in the best interests of APS customers and took reasonable and prudent steps to protect those interests.

- As a result of these actions, APS successfully weathered a storm that engulfed virtually every other investor-owned utility in the Western United States without having to threaten bankruptcy, request emergency rate relief, defer significant purchased power costs, institute capacity-related curtailments, or be forced into high-priced, long-term purchase power agreements.

- During a period of significant change and substantial uncertainty in the electric utility industry, APS and its affiliates acted ethically and appropriately to comply with regulatory requirements relating to restructuring in Arizona. In many respects, APS and its affiliates went far beyond mere technical compliance and instead acted aggressively to protect customers in instances where the Electric Competition Rules provided little guidance.

- APS has neither surrendered nor neglected its obligation to serve customers. Because APS has not and will not entrust that obligation to others, it is well-positioned to *continue* to provide reliable, reasonably-priced service to Arizona consumers.

- Although APS participated vigorously in the debate surrounding the various state and federal efforts to restructure the electric industry, once the responsible state or federal regulatory authority set its restructuring policies, APS was a leader in implementing both their letter and spirit.

- When contemplated APS actions on behalf of customers required regulatory approval or a variance to a Commission rule, APS requested relief from the Commission in an open and legally appropriate manner.

- Despite the changes made by the Commission to the 1999 Settlement, APS continues to comply with its obligations under that Agreement and to work toward reasonable regulatory solutions to address the impacts on itself and its affiliates of the changed circumstances that both precipitated and resulted from those changes.

Regarding specific questions that arose during the proceedings on the APS Financing Application, APS' and its affiliates' actions were entirely lawful and reasonable and protected both APS customers and investors. This Report explains that:

- Pinnacle West Energy Corporation ("PWEC") was formed to implement the Commission's requirement that incumbent utilities divest their generation. Its formation was not only specifically authorized by the Commission in Decision No. 61973 as being in the public interest, but the Commission expressly stated that it *supported* the transfer of *all* of APS' generation to an affiliate. The Commission also acknowledged in the 1999 Settlement that sales between APS and its generation affiliate at market based rates would benefit customers, would not violate Arizona law, would not provide APS' affiliate with an unfair competitive advantage, and were in the public interest. Subsequent to PWEC's formation, the Commission was informed on several occasions that PWEC generation was going to be used, and even relied upon, to serve APS customers.

- Because the Electric Competition Rules prevented APS from constructing new generation, PWEC and its parent company, Pinnacle West Capital Corporation ("Pinnacle West"), took action to protect APS during the turmoil of the Western power crisis in 2000 and 2001. PWEC both brought in temporary generation to allow APS to meet short-term summer capacity needs driven by rapid load growth, and constructed permanent capacity to provide a long-term resource for APS customers.

- By dedicating its capacity to APS customers and not selling forward into the lucrative California markets, PWEC prevented APS from falling victim to the rush into high-priced, long-term contracts that occurred in California, Nevada and elsewhere during the height of the Western power crisis. Unlike utilities in other states, APS knew that capacity would be available for its customers at reasonable prices. PWEC's actions in no small part allowed APS to continue providing the rate reductions as provided for in the 1999 Settlement while other utilities throughout the West sought significant rate increases.

- Because PWEC was entitled to receive *all* of the APS generation under the 1999 Settlement, the receipt of such generation and its subsequent operation by PWEC after 2002 was a valid and reasonable business assumption—indeed, the only valid and reasonable business assumption—for PWEC to have presented to rating agencies in requesting a contingent credit rating. Further, the assumptions presented to those rating agencies to support their modeling were based on assumed sales at market prices. Thus, the results were indifferent as to whether PWEC had a contract with APS at market prices or simply sold to a third-party at the same market prices. There was no representation made to the rating agencies that PWEC actually had a signed multi-year contract with APS or was entitled to receive a multi-year contract except in conformance with the Electric Competition Rules.

- APS never entered into any supply agreement that violated Rule 1606(B), which was not to take effect for APS until January 1, 2003. In fact, during its 2001 *request* to the Commission for a partial variance to that rule, APS specifically confirmed that if the Commission denied the requested variance, APS would proceed with "good faith compliance with Rule 1606(B) as written."

- The APS Code of Conduct contained, as required by the 1999 Settlement, a provision relating to the supply of APS generation during the two-year delay of divestiture to ensure that APS' Competitive Electric Affiliate, APS Energy Services ("APSES"), was not given an unfair competitive advantage. In the decision approving APS' Code of Conduct, the Commission specifically found that the Code of Conduct jointly proposed by Staff and APS "satisfies the requirements of A.A.C. R14-2-1616 and Decision No. 61973." APS has complied with that provision.

- As required by applicable regulations, APS applied for the modifications required to be made to the air permits for the PWEC West Phoenix and Saguaro Power Plant units because these new units were under common corporate control with the existing APS units. In a similar fashion, APS holds the air permit for other jointly-owned facilities that do not involve an APS affiliate.

Electric Competition Checklist

1	Opened service area to competition	☑
2	Dismissed court appeals to Electric Competition Rules	☑
3	Reduced rates by more than $400 million	☑
4	Resolved stranded costs	☑
5	Assured reliable electric service to customers	☑
6	Corporate restructuring to comply with the rules	☑
7	Developed systems and processes to support direct access	☑
8	Filed direct access rates	☑
9	Supported AISA protocols	☑
10	Developed WestConnect RTO	☑
11	Adopted retail Code of Conduct	☑
12	Timely filed adjustment clause application	☑
13	Filed all required reports	☑
14	Formed APSES as competitive ESP affiliate	☑
15	Provided nondiscriminatory open access to transmission and distribution systems	☑
16	Met Provider of Last Resort obligations	☑
17	Divested generation to PWEC	Suspended
18	Implemented Rule 1606(B)	Suspended
19	Implemented new Track B requirements	☑

This Report includes a discussion of historical background and regional context. It is impossible to fully consider the events of the last several years, since the execution of the 1999 Settlement and the adoption of the current Electric Competition Rules, without a detailed understanding of this background. It also is necessary to consider the significant changes and the increasing uncertainty in both state and regional electric markets over this period, and to view the actions of APS and its affiliates in that context.

When the initial Electric Competition Rules were passed and the 1999 Settlement signed, many believed that retail Electric Service Providers ("ESPs") would sweep into the state and take significant amounts of load from incumbent utilities. Little attention was paid to wholesale power markets, which in 1999 were still relatively stable and, like today, largely subject to exclusive federal jurisdiction. In fact, no independent power producer apart from Enron, which also was an ESP, participated in the 1999 Settlement proceeding.

Despite a requirement that APS divest all of its generation to facilitate the development of the retail marketplace, and despite the lack of clear "rules of the road" from the Commission regarding how APS could operate, the Commission still expected the Company to take the steps necessary to serve all present and future customers. Moreover, APS was expected to do so reliably and at just and reasonable rates. Further, following the 1999 Settlement, APS implemented a series of rate reductions and, absent an emergency, could not increase rates even if its costs rose unexpectedly. In 1999, however, APS needed to purchase increasing amounts of power from the wholesale market and its peak demand was growing rapidly. Fortunately for APS customers, over the next few years, the actions taken by APS and its affiliates and the actions taken in neighboring states like California stand in stark contrast.

In California, investor-owned utilities divested their generation to non-affiliates and the utilities and the California commission lost control over those resources. In California, generation shortages caused rolling blackouts throughout the state. And in California, the shock of two summers caused all three major investor-owned electric utilities to defer billions of dollars of wholesale power costs, impose major rate increases, and ultimately forced the California Department of Water Resources ("CDWR") to take over generation procurement. One utility is still in bankruptcy and all have been financially ravaged in the credit markets. Finally, in California, CDWR entered into high-priced, long-term wholesale power contracts that were significantly above the cost of generation in an effort to stabilize the chaos that had rocked the state. California is now litigating and attempting to abrogate those contracts, causing increased turmoil in energy capital markets.

On the other hand, in Arizona, APS negotiated with the Commission to ensure that divestiture would take place only to an affiliate of APS. Ultimately, the Commission stopped divestiture altogether. And in Arizona, PWEC installed expensive temporary summer capacity and constructed new generation resources to meet the needs of APS customers. Not coincidentally, the lights in Arizona stayed on. While rates elsewhere spiraled out of control, APS passed on to customers the rate reductions that it had agreed to without deferring any wholesale power costs and still retains its investment grade credit ratings. This was due in no small part to the fact that in Arizona, the construction of new generation by PWEC eliminated the panicked buying of long-term contracts because APS knew that capacity would be available for its customers.[1]

[1] The history of the steps that APS and PWEC reasonably took to ensure that APS customers were not subjected to the vagaries of a dysfunctional wholesale power market will be explained in greater detail in the rate case that APS will file with the Commission.

In retrospect, the robustness of wholesale power markets was more important in the overall process of electric restructuring than many had envisioned. While California has essentially stalled retail competition and is considering an aggressive return to a more traditional utility model, Arizona has not suffered such a result. But the uncertainty for incumbent utilities in Arizona continues. There now exists a mix of vertically-integrated utilities with a "Track B" requirement to seek some power supplies for an undefined period of time from the wholesale market (even when APS' supplies are sufficient) and with the continuing risk that retail load will leave for direct access service. But the prudent actions of APS and its affiliates during this period have at least left the Commission and the state with significant flexibility as to where Arizona moves in the future with electric competition.

II. INTRODUCTION AND SCOPE

A. Introduction

Decision No. 65796 (April 4, 2003), which approved APS' Financing Application, directed Staff to commence a preliminary inquiry into APS' and its affiliates' compliance with:

- the Electric Competition Rules;
- Decision No. 61973;
- APS' Code of Conduct; and
- applicable law.

This Report addresses each of these issues, while providing background and context that the Company believes is important to consider on each of these issues. This Report also responds specifically to some of the assertions that were made during the hearing on APS' Financing Application in Docket No. E-01345A-02-0707.

B. Organization of Report

Section I of the Report is an Executive Summary. Section II provides an introduction to the Report, defines the scope of issues addressed pursuant to Decision No. 65796, and sets forth certain definitions and concepts that will be used throughout the report.

Section III provides a relatively extensive factual and historical background of APS' and its affiliates' role and involvement in the restructuring of the electric power industry in Arizona. This background discussion also addresses events outside Arizona that have had a significant effect on the Company and its affiliates due to the regional nature of the Western electricity grid.

Section IV discusses each of the categories of issues identified in Decision No. 65796, including a discussion of "applicable law." Section V then responds specifically to certain issues raised during the hearings on APS' Financing Application earlier this year. Section VI is a conclusion. Finally, a Glossary of Terms is provided at the end of this Report.

C. Scope of Report

Decision No. 65796 sets forth the scope for this Report. Pursuant to that decision, this Report addresses (i) APS' and its affiliates' compliance in Arizona with the Electric Competition Rules, A.A.C. R14-2-1601 to -1617; (ii) Decision No. 61973, which approved the 1999 Settlement; (iii) APS' Code of Conduct, which was approved in Decision No. 62416; and (iv) applicable law.

This Report also addresses specific matters referred to in Decision No. 65796 and discusses the steps that APS took to respond to Commission orders and decisions and to comply with the Electric Competition Rules. These include the corporate restructurings undertaken to satisfy requirements in the Electric Competition Rules. They also include the significant steps that APS undertook to implement retail direct access in Arizona, and APS' efforts to further the development of wholesale markets from which the Company will continue to be a significant buyer. Most importantly, however, this Report demonstrates the steps APS took to meet a rapidly growing customer load during a period of extreme volatility in wholesale power markets while managing both risk and cost.

Because the issues that Decision No. 65796 directed Staff to evaluate are Arizona issues, this Report focuses primarily on Arizona and Arizona law. Where applicable, however, this report discusses regional or national issues as well to provide necessary context.[2] Similarly, most of the matters raised in APS' Financing Application hearing occurred over the last three to four years. To fully capture the evolution of the Electric Competition Rules, however, this Report also addresses some developments that occurred prior to 1999.

D. Definitions and Concepts

For purposes of this Report, an understanding of certain definitions and concepts is necessary. First, the term "affiliates" when used in this report refers, unless otherwise noted, to those APS' affiliates involved in the electric utility industry in Arizona. Thus, the term includes Pinnacle West, which is the parent entity in the holding company structure; PWEC, which is the wholesale generation affiliate; and APSES, which is a retail Electric Service Provider pursuant to A.A.C. R14-2-1601(15).[3]

Second, APS has interpreted the term "applicable law" broadly to refer to the specific Commission orders discussed above, applicable federal and state antitrust laws and regulations, Arizona laws and regulations relating to utilities and electric competition, applicable regulations of the Federal Energy Regulatory Commission ("FERC") and the Securities and Exchange Commission ("SEC"), and the Federal Power Act, where applicable.

Third, the term "APS Code of Conduct" refers to the retail Code of Conduct approved in Decision No. 62416 (April 3, 2000).

Fourth, the term "Electric Competition Rules" is defined to include R14-2-1601 to R14-2-1617, which are the principal rules directed toward retail electric competition. APS has not for purposes of this Report included specific discussions of the various amendments that were made to R14-2-201, *et seq.*, during the rulemakings, nor has it included a discussion of the

2 Given the scope identified in Decision No. 65796, this Report does not cover actions of APS and its affiliates outside of Arizona. For example, APSES has received a certificate from the California Public Utility Commission and has been significantly involved in direct access issues in that state. It also provides services in California, as well as Texas, Nevada, and other states. Similarly, PWEC is constructing a power plant in Nevada, which has certain regulatory requirements not relevant to this Report.

3 Because the issues addressed in this Report relate to electricity regulation, the term "affiliates" does not include SunCor Development Company, which is a Pinnacle West real estate subsidiary, or El Dorado Investment Company, which is Pinnacle West's venture capital subsidiary, or their respective subsidiaries. NAC Holding Inc. is a subsidiary of El Dorado based in Atlanta, Georgia that manufactures dry cask storage for the nuclear industry. Given the narrow business focus of NAC, it is not considered an electric industry affiliate for purposes of this Report.

Environmental Portfolio Standard found in Rule R14-2-1618, which is not directly related to retail electric competition.

III. BACKGROUND AND CONTEXT

A. Development of the Electric Competition Rules

Many states, including Arizona, began to consider retail electric competition after the California Public Utilities Commission published its "Blue Book" report in 1994. The Commission first opened an investigation on retail electric competition in 1994, and the first phase of the investigation concluded in 1995. In early 1996, Staff requested comments from interested parties to help develop the first set of electric competition rules.

That request for comments articulated the original Staff and Commission view of the appropriate goals for retail electric competition. One central goal was to encourage the hoped-for benefits of retail competition, "including increased innovation and efficiency, holding prices down, responsiveness to customer demands, and customer choice among suppliers and products."[4] Additionally, however, the Commission's original goals recognized that retail electric competition should "limit potential harm to utilities and utility investors" and not adversely affect system reliability.[5] Also, customers who would not or could not participate in the competitive market were to be protected from rate increases attributable to competition.

All of the goals articulated in 1996 were focused on *retail* competition. Thus, the Commission's Staff noted that market impediments "such as the exertion of retail market power by incumbent utilities which blunts competitive forces and high retail transaction costs for market participants" should be avoided.[6] The focus was on developing a vibrant retail market and encouraging a variety of retail market developments, including ESP contract development, ESP interconnection arrangements, spot market development and retail rate unbundling.[7]

By mid-1996, the Commission issued its first proposed electric competition rules. After numerous public meetings and volumes of written comments, rules were adopted by the Commission in Decision No. 59943 (December 26, 1996). As originally enacted, the electric competition rules did not contain many of the provisions that some parties have since claimed are "cornerstones" of restructuring. For example, there was no required separation of competitive and non-competitive electric services, no code of conduct requirement, no competitive bidding requirement and no divestiture requirement. Under these 1996 rules, retail open access was to begin in phases starting in 1999.

The 1996 electric competition rules were challenged by virtually all of the incumbent electric public service corporations, including APS. The challenges included claims that it was unlawful to amend the noncompetitive Certificates of Convenience and Necessity ("CC&Ns") of incumbent utilities to permit competition, that the rules constituted an impairment of contract and were a regulatory taking of private property, that the rules violated principles of due process and equal protection, and other procedural and substantive claims. No merchant generator or competitive retail ESP challenged the 1996 rules, however, even though the rules did not address

[4] February 22, 1996 letter from Utilities Division Director Gary Yaquinto to interested parties.

[5] *Id.*

[6] *Id.*

[7] *Id.*

the "cornerstone" issues listed above. The 1996 electric competition rules remained in place until 1998, when the Commission decided to reopen them.

In mid-1998, a new set of electric competition rules was proposed and adopted on an interim basis in Decision No. 61071 (August 10, 1998). These new rules, which were finalized on a "permanent" basis when rehearing applications were denied on December 31, 1998, added the mandatory divestiture requirement for the first time, but still made no mention of competitive bidding for Standard Offer load. The rules also eliminated the Solar Portfolio Standard, which was the predecessor of the current Environmental Portfolio Standard. The 1998 electric competition rules lasted only six days, however, before they were stayed by the Commission pending yet another rulemaking process.

In 1998, the Commission first focused on divestiture as a necessary component to its vision of retail competition. Despite the objections of the utilities to this concept in general, the debate centered on whether the divestiture should be to a third party, should be conducted through an auction, or whether utilities should be allowed to divest to affiliates.[8] In late 1998, the Executive Secretary of the Commission, with Staff acting as a party in negotiations, brokered a settlement of these and other contentious electric competition issues involving APS and Tucson Electric Power Company ("TEP"). Under the 1998 Settlement, APS would be permitted to retain its generation despite the new electric competition rules—and even acquire some of TEP's generation—but would divest most of its high voltage transmission system to TEP. Neither utility would have to write-off any stranded costs. The 1998 APS-TEP-Staff settlement was appealed to the courts by the Arizona Attorney General's Office and other intervenors before the Commission could even hear it. After Commission hearings on the settlement were stayed, the settlement was withdrawn.

Also in 1998, the Legislature enacted House Bill 2663 ("H.B. 2663") regarding retail electric competition. This legislation confirmed the authority of the Commission to adopt various provisions of the Retail Electric Competition rules, to the extent such confirmation was necessary. It also included provisions to address electric competition for certain defined Public Power Entities, primarily Salt River Project, which were not subject to the Commission's jurisdiction. The Legislature's directives for electric competition involving Public Power Entities, however, were significantly different in certain key respects from the Commission's Electric Competition Rules, both in 1998 and as later modified. For example, H.B. 2663 did not require divestiture of generation by Public Power Entities nor did it address wholesale procurement by Public Power Entities in any respect. These differences would lead to even more difficulty in smoothly implementing the policy in Arizona.

The next rulemaking process before the Commission culminated in essentially the current version of the Electric Competition Rules. First proposed in April 1999, these rules were adopted

[8] For example, in its original comments on the rules, APS wrote that it "does not believe that divestiture is necessary or desireable" and that mandatory divestiture was beyond the Commission's legal authority and should be left to the discretion of the individual utility's management. *See* APS' Response to Staff's Questions on Restructuring (June 28, 1996) at iv. Later, in response to Decision No. 60977 (June 22, 1998) regarding stranded cost recovery, APS again challenged the Commission's authority to compel divestiture. *See* APS' Application for Rehearing (July 10, 1998) at 4-6.

in Decision No. 61969 (September 29, 1999). As originally proposed, there still was no competitive bidding requirement for Standard Offer load. In fact, the Concise Explanatory Statement that accompanied the approved rules as required by the Arizona Administrative Procedures Act still specifically rejects competitive bidding:

> Analysis: There appears to be some confusion concerning the meaning of the term "open market." We do not wish to impose constraints on energy procurement that would be associated with a competitive bid process. Consequently, we will modify Section 1606(B) to clarify the term "open market." Our clarification is not substantive.[9]

The resolution set forth in the Concise Explanatory Statement was simply to require that Standard Offer power be acquired, after divestiture, in "an open, fair and arm's-length transaction with prudent management of market risks, including management of price fluctuations." Ultimately, however, language on competitive bidding was added to Rule 1606(B) during the Commission's Open Meeting deliberations—primarily at the urging of Enron and Commonwealth Energy, two ESPs that were involved in the rulemaking but who are no longer conducting business in Arizona.[10]

Despite the amendment to the rule during the open meeting, two aspects of Rule 1606(B) still seemed clear with respect to competitive bidding. First, the rule was premised on the fact that the Utility Distribution Company would not itself own *any* generation and would have to acquire all of its generation supplies from the wholesale market. And, second, there was a clear concern about risk management and protecting Standard Offer customers from significant price volatility.

B. The 1999 APS Settlement Agreement

Also in 1999, the Commission asked APS and TEP to meet with affected customer groups and try to negotiate new settlement agreements having more broad-based support than the 1998 settlement. APS commenced negotiations with all of its major customer groups, with the Commission Staff participating as an observer.[11] On May 14, 1999, APS and all of its major consumer groups filed the 1999 Settlement with the Commission.

The 1999 Settlement called for numerous concessions from APS. Although in both the Electric Competition Rules and Decision No. 60977 (June 22, 1998) (the "Generic Stranded

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[9] Decision No. 61969 (September 29, 1999) at App. B, pp. 27-28.

[10] The addition of the competitive bidding language was done without any cost-benefit analysis or economic impact analysis.

[11] Parties to those negotiations, and ultimately the settlement, included a broad cross-section of APS customers, including the Residential Utility Consumers Office ("RUCO"), the Arizona Community Action Association and the Arizonans for Electric Choice and Competition ("AECC"), which is a coalition of companies and associations that support competition. Most of the members of AECC are APS customers. Many other interested parties participated in the proceedings before the Commission on the 1999 Settlement.

Costs Order"), the Commission had assured incumbent utilities of *full* stranded cost recovery, APS agreed to a $234 million write-off of prudently incurred costs and to a series of five rate reductions for both Standard Offer and direct access customers. APS also agreed, absent emergency circumstances, not to seek any rate increases prior to mid-2004 and to forego recovery of any increased purchased power costs incurred until after mid-2004.

In return, Pinnacle West, but not APS, received a partial waiver of some substantive Affiliate Interest Rules (A.A.C. R14-2-801 to -806). Both Pinnacle West and APS received partial waivers of some non-substantive reporting requirements in these rules. Also, APS was assured that it could divest its generation assets to a newly-created Pinnacle West subsidiary, PWEC. This was a significant issue for APS, because it allowed APS' generation to remain under common corporate control post-divestiture rather than having third-parties with potentially no ties to Arizona take over that generation. The experience of California, which required divestiture of much of the state's generation to third parties, bears out the wisdom of that approach.

Significantly, the Settlement also provided that APS' new generation affiliate would not be subject to regulations beyond those applying to any other owner of generation in Arizona, and could sell at market based rates to APS. In approving the Settlement, the Commission expressly stated that it *supported* the transfer of *all* of APS' generation to an affiliate.[12] The Commission also acknowledged in the 1999 Settlement that sales between APS and its generation affiliate at market based rates would benefit customers, would not violate Arizona law, would not provide APS' affiliate with an unfair competitive advantage, and were in the public interest.[13]

The 1999 Settlement was approved by the Commission in Decision No. 61973 (October 6, 1999). On November 24, 1999 an addendum to the Settlement was executed to address changes made during the open meeting at which the Settlement was approved. Specifically, despite assurances in Decision No. 60977 that APS would receive full recovery of the significant costs of asset divestiture, APS agreed to give up a third of such recovery. Also, APS agreed to implement a code of conduct that was more restrictive than required under the Electric Competition Rules.

The 1999 Settlement was later upheld as lawful and binding on all parties and the Commission by the Arizona Court of Appeals in actions brought both by Enron and the Arizona Consumers Council. During the pendency of that litigation, APS wrote-off $234 million of what the Commission had already determined to be prudently-incurred costs. APS also decreased its rates in 1999, 2000, 2001, and 2002. This July, APS will reduce rates yet again, even though other aspects of the 1999 Settlement were changed by the Commission. These rate reductions will result in cumulative savings to customers of more than $400 million through June 30, 2004. And, as will be discussed in more detail below, APS has spent literally millions of additional dollars and thousands of man-hours to comply with the Electric Competition Rules, including the divestiture requirement that ultimately was repealed by the Commission.

12 Decision No. 61973 at 10.

13 *See id.* at Attachment 1, Section 4.4.

C. The APS Code of Conduct

As required by Decision No. 61973, APS submitted an initial proposed code of conduct on October 28, 1999. This retail code of conduct was in addition to the Company's FERC Code of Conduct that applies to wholesale functions involving APS and its affiliates. APS submitted a final proposed code of conduct on January 5, 2000 after receiving and considering comments from Staff and other interested parties. The nine implementing Policies and Procedures were filed with the Commission on January 12, 2000.

In response to both the original filing by APS and the final proposed code of conduct filed by APS in January 2000, Commission Staff filed an alternative proposed code of conduct with the testimony of its expert witness, Gretchen McClain. Although APS, Staff and other interested parties disagreed on certain issues, APS and Staff ultimately reached agreement on modifications to the Staff proposed Code of Conduct. APS and Staff filed a Stipulation and a Joint Proposed Code of Conduct reflecting that agreement.

In Decision No. 62416, the Commission adopted the Joint Proposed Code of Conduct with certain modifications, clearly noting that the Code of Conduct applied "to the conduct of APS and its competitive electric retail affiliates."[14] In that decision, the Commission concluded as a matter of law that the Code of Conduct complied with the requirements of Rule 1616 and Decision No. 61973. That Code of Conduct, and the associated Policies and Procedures, remain in effect today.[15]

The APS Code of Conduct addressed each of the nine subjects specified in Rule R-14-2-1616, with particular emphasis on such core issues as cross-subsidization by APS customers and anti-competitive discrimination. The Policies and Procedures implementing the APS Code of Conduct address the following issues:

- affiliate accounting policies;
- access to information;
- compliance;
- contracting for personnel services between APS and its Competitive Retail Electric Affiliates;
- ESP contracts and requests for service;

[14] Decision No. 62416 at 5. APS' only Competitive Electric Retail Affiliate was, and still is, APSES.

[15] For purposes of this Compliance Report, the Code of Conduct approved by the Commission in Decision No. 62416 is referred to as the "APS Code of Conduct." As required in Decision No. 65154, APS filed a new proposed Code of Conduct with the Commission on November 12, 2002 (the "Proposed Code of Conduct"). The Proposed Code of Conduct would apply to APS and its interactions with its Competitive Electric Affiliates, which is defined in the Proposed Code of Conduct to include both APSES and PWEC. A hearing is anticipated later this year on the Proposed Code of Conduct after Staff completes its review of the Track B implementation.

- joint promotion, sales, and advertising with a Competitive Retail Electric Affiliate;
- physical separation of entities;
- shared officers and directors; and
- training.

Throughout the entire process of developing the APS Code of Conduct, the focus of the Commission, Staff, and the intervenors was on protecting *retail* competition and ensuring that APS did not unduly favor APSES.[16] There was no discussion of APS' purchases of power from the wholesale market and no merchant generators other than Enron intervened in the proceeding. Enron's principal comments on APS generation focused on the supply of excess generation by APS.[17] That may have been because the parties understood that the FERC Standards of Conduct and FERC Code of Conduct would address APS' relationships with any affiliate that engaged in wholesale power sales, such as PWEC.[18] It also was clear throughout APS' testimony that APS would not be providing competitive services, including Interim Competitive Services, but that such competitive services would "be provided only through a separate competitive affiliate."[19]

D. Implementation of the Electric Competition Rules

APS and its affiliates have worked closely with the Commission, Staff and other stakeholders to implement the Electric Competition Rules since they were first adopted in 1996. Implementation has taken many forms, from broad corporate restructuring to the far more specific processes of developing computer systems and software to transfer data between the Company and ESPs serving direct access customers. In very general terms, the implementation efforts of APS are discussed below.

Corporate Restructuring

The foremost and, in many respects, longest lead-time issue in complying with the Electric Competition Rules involved the corporate restructuring efforts undertaken by APS and Pinnacle West. As a result of the Commission's rules and decisions, APS and its affiliates have undertaken the following corporate restructuring actions since 1999:

- The implementation of a corporate restructuring to accommodate the Electric Competition Rules and implement direct access, including the movement of shared corporate support services to Pinnacle West.

16 *See* Rebuttal Test. of Gretchen McClain on behalf of The Arizona Corporation Commission, Docket Nos. Docket No. E01345A-98-0473, E01345-97-0773 &RE-00000C-94-0165 (January 18, 2000) at 5.

17 See the discussion of Supply of Generation below at Section IV(B).

18 See the discussion of FERC Code of Conduct below at Section IV(D)(1).

19 Direct Test. of Jack E. Davis on behalf of APS, Docket Nos. E-01345A-98-0473, E-01345-97-0773 &RE-00000C-94-0165 (January 21, 2000) at 14-15; *see also* APS Response to First Set of Data Requests, Question 4 (January 14, 2000).

- The formation of APSES, a retail ESP and energy services company, to offer Competitive Electric Services separately from APS.
- The formation of PWEC to receive APS' generation assets following the Commission-required divestiture of such generation at the end of 2002 and to construct any generation assets needed to reliably serve customers.
- The implementation of a multi-year process to result in the transfer, as required by the Electric Competition Rules, of APS' generation to PWEC. This involved significant cost and effort in preparing an application for FERC approval of the transfer; preparing a Nuclear Regulatory Commission application for license transfer authority; negotiations with co-owners, lenders and deed-holders; preparing permit transfer applications; and undertaking numerous other transactional matters relating to divestiture.
- The reshaping of APS as a "wires only" Utility Distribution Company, as then contemplated by the Electric Competition Rules, with a focus on attempting to provide reliable Standard Offer service solely through purchased power, and unbundled distribution service to all retail customers within its service area.
- The formation of a power marketing organization at Pinnacle West to comply with the structural separation requirements of the Electric Competition Rules.
- Active participation in the formation of WestConnect, to which APS would transfer operational control of transmission.
- The implementation of another corporate restructuring plan after the Commission changed course on divestiture and ordered APS to retain its generation, including the transfer of power marketing operations back to APS.

Process Standardization Working Group Participation

Since 1999, APS has taken a leading role in laying the groundwork for retail direct access in Arizona. It has been an active participant in the Process Standardization Working Group, which was established to streamline technical implementation of the Electric Competition Rules by addressing matters relating to such things as billing, metering standards, data interchange, meter reading protocols and certain policy issues. Since that group was formed, almost 150 discrete issues have been identified, most of which have been resolved through collaborative efforts.

Internal Systems and Process Development

APS has expended significant resources to develop internal practices for retail direct access and to acquire the necessary systems and hardware to comply with the Electric Competition Rules. These implementation activities include:

- Active participation at every stage of each of the rulemaking proceedings, investigative dockets, and generic dockets to consider issues relating to retail electric competition.

- The creation and development of electronic systems to support direct access. This involved an investment of more than $20 million in technology, including the creation of a secure virtual private network, new billing software and systems, an electronic data interchange system and associated protocols, training, and personnel for all parties involved.
- The development of procedures and practices for generation settlement and transmission between APS and load-serving ESPs, including the development of the AISA protocols.
- The development of a detailed manual for ESPs and its subsequent modification through several presentations and workshops.
- The development of Schedule 10, which has been approved by the Commission and implements APS' rules and regulations for direct access service, as well as an ESP Service Acquisition Agreement to address the business relationship between APS and ESPs offering service in APS' distribution service area.
- Conducting internal training, including Code of Conduct training and training related to ESP service and other rule requirements, involving all affected APS, Pinnacle West and APSES employees.

Virtual Unbundling

Another significant undertaking for APS was to develop the "virtual" unbundling of Standard Offer service bills that the Electric Competition Rules directed. Under those rules, Standard Offer service was considered a "Noncompetitive Service." However, to allow customers to compare a "bundled" Standard Offer bill from their incumbent supplier with an offering from a competitive ESP, the Electric Competition Rules directed APS to show on its customer billing statements a breakdown of the bill by service component—such as generation, transmission, metering, and billing and collection costs.

This process and the reprogramming of APS' Customer Information System, which generates and prints the bills, has resulted in a second page being added to APS' normal bill to show the virtual unbundling and has required APS to increase staffing associated with its billing processes. Each year, that second page results in about 10.8 million extra sheets of paper being printed, stuffed into billing envelopes, and mailed to our customers.

APSES Activities

APSES is now in its fourth year of operation. It was formed along with the first competitive ESPs in Arizona and is one of the few remaining ESPs with an active CC&N. APSES received its CC&N in Decision No. 61669 (April 29, 1999). APSES has served direct access customers in both California and Arizona, and has been certificated to serve customers in Texas and Nevada. In California, APSES was the first ESP to deliver competitively-priced electricity to retail customers in 1997. In Arizona, it was the only ESP to serve customers in the service territories of all three major Arizona electric utilities—APS, Salt River Project and TEP. Today, APSES continues to serve direct access customers in California, and provides energy management services throughout the Southwest.

E. Transmission and Wholesale Market Activities

Although most of the Electric Competition Rules are focused on retail activities, some specifically apply to transmission or wholesale electric markets. APS has been significantly involved in these areas and in many cases has gone beyond the minimum requirements of the rules to adopt policies or practices that will help wholesale markets or provide transmission access for retail suppliers. Examples are discussed below.

AISA Protocols

Rule 1609(D) directs the formation of an Arizona Independent Scheduling Administrator ("AISA"). This organization was to help provide nondiscriminatory transmission access on an interim basis until a Regional Transmission Organization ("RTO") became functional. The AISA was designed to calculate the Available Transmission Capability of transmission paths, develop an Open Access Same-Time Information System ("OASIS"), implement and oversee the nondiscriminatory application of operating protocols to ensure statewide consistency for transmission access, provide a dispute resolution process, standardize scheduling procedures, and implement a transmission planning process. Essentially, the AISA was the first step in moving toward an RTO for Arizona.

APS provided much of the AISA's initial funding and spent thousands of employee hours to comply with the requirements in Rule 1609(D). More importantly, however, the process resulted in innovative protocols to facilitate retail direct access.

Specifically, retail transmission rights were to be allocated on a pro rata basis until auction and trading mechanisms were in place for these rights. This placed a significant burden on scheduling coordinators that are serving retail direct access customers, because a pro rata allocation on APS' transmission system would require some generation to come across each of APS' four key transmission delivery paths. For example, a scheduling coordinator might have purchased generation at Palo Verde, but would have to schedule on a pro rata basis from Four Corners, Navajo and Mead as well as Palo Verde. To mitigate this burden and facilitate the ability of ESPs to serve their customers, APS agreed to exchange up to 200 MW of its Palo Verde to APS transmission capacity with scheduling coordinators serving direct access customers in APS' service territory. Thus, ESPs could obtain all of their generation from the most liquid trading hub connected to APS' system and not be forced to schedule pro rata over all of APS' delivery paths.

To achieve regulatory acceptance of this approach, APS worked a great deal directly with FERC and Staff. The resulting protocols are now incorporated into APS' FERC-approved Open Access Transmission Tariff ("OATT").

Desert STAR and WestConnect

Rule 1609(F) requires each Affected Utility to "make good faith efforts to develop a regional, multi-state Independent System Operator or Regional Transmission Organization." The

RTO in which APS is participating pursuant to this rule, WestConnect, is based predominantly on the market design created by Desert STAR. Desert STAR discussions began as early as 1997 with the goal of creating an independent administrator for transmission operations in the Southwest (an Independent System Operator). APS was one of the original and most active participants in the Desert STAR discussions and helped coordinate the overall effort. The participants in the Southwest eventually created Desert STAR as a non-profit corporation and selected an independent board in 1999.

In early 2001, transmission owners in the area began to analyze the potential benefit of changing the basic framework of the organization into a for-profit entity. For a variety of reasons, it appeared that the better course was to sunset the Desert STAR organization completely and to create a new and innovative limited liability company structure for its successor, WestConnect. The WestConnect process resulted in a substantially complete proposed FERC tariff that was filed in October 2001.

The WestConnect applicants currently are APS, El Paso Electric Company, Public Service Company of New Mexico, and TEP. The Western Area Power Administration ("WAPA"), Salt River Project and the Southwest Transmission Cooperative are participating transmission owners. To achieve as broad and effective a regional system as possible, WestConnect has continued to explore having other transmission owners in Colorado, Wyoming and southern Nevada participate.

FERC issued an order conditionally approving WestConnect as an RTO on October 10, 2002.[20] Among the specific aspects of WestConnect that were approved in that order were:

- A "license plate" pricing model, with a transition to highway-zonal in 2009;
- Physical rights congestion management model as a "day one" proposition;
- The governance structure and board selection process; and
- A revenue recovery mechanism for WAPA revenues lost as a result of the WestConnect pricing structure

Under APS' leadership, WestConnect is also exploring ways to accelerate a phase-in of certain RTO functions. That effort is geared toward finding ways to implement RTO functions earlier than the time required to create a formal organization and acquire systems and personnel for full operations, as well as to identify functions offering significant benefits in relation to their costs.

In addition, the Seams Steering Group-Western Interconnection ("SSG-WI") is serving as a discussion forum for facilitating the creation of a Seamless Western Market and for proposing resolutions to issues associated with differences in RTO practices and procedures. SSG-WI includes the California ISO, RTO West, WestConnect, and other market participants. APS is significantly involved in moving this group forward and offering solutions to issues raised.

[20] *Arizona Public Service Company, et al.*, 101 FERC ¶ 61,033 (2002).

Western Electricity Coordinating Council

APS has been and continues to be a leader in the Western Electricity Coordinating Council ("WECC"). The WECC was formed in April 2002 by the merger of the Western Systems Coordinating Council ("WSCC"), the Southwest Regional Transmission Association, and the Western Regional Transmission Association. The WECC is responsible for coordinating and promoting electric system reliability, as had been done by the WSCC since its formation nearly 35 years ago. In addition to promoting a reliable electric power system in the Western Interconnection, the WECC has been important in promoting efficient competitive power markets, assuring open and non-discriminatory transmission access among members, providing a forum for resolving transmission access disputes, and providing a forum for coordinating the operating and planning activities of its 145 members.

APS is actively involved in almost every committee and group within the WECC. More than perhaps any other individual member, APS has taken a leadership role within the WECC. APS President and Chief Executive Officer, Jack Davis, serves on the WECC Board of Directors and is past Chairman of the WSCC. APS' Director of Transmission Planning and Operations, Cary Deise, is the current Chair of the Reliability Management System Reliability Compliance Committee and the Vice Chair of the Joint Guidance Committee and of the Planning Coordination Committee. Mr. Deise is also the former Chair of the Reliability Management Systems Standards Development Task Force and of the Operating Practices Subcommittee. APS employees serve on the Steering Committee of the Operating Committee, as Chair of the Information Management Subcommittee, as sub-regional study group Chair of the Operating Transfer Capability Policy Committee, and as Chair of the System Review Work Group within the Planning Coordination Committee. These voluntary commitments within the WECC go far beyond the minimum requirements expected of WECC members.

Joint Planning Efforts and Joint Use of Facilities

Joint planning, where several utilities coordinate to undertake planning or construction of projects that would not make economic sense for an individual company, also helps facilitate wholesale competition. While joint planning is neither new nor unique, the extent to which APS (as well as some other Arizona utilities) participates in joint projects and planning is significant when compared to other regional or national areas. APS also has a long and continuing history of joint planning and joint use of transmission and generation facilities locally, within Arizona, and in the Western United States.

At the WECC, joint planning efforts have primarily occurred through various committees including the Board of Trustees, the Regional Planning Committee, the Planning Coordination Committee, the Operations Committee, the Joint Guidance Committee, the Operating Transfer Capability Policy Group, the Technical Studies Subcommittee, the Reliability Subcommittee, the Compliance Monitoring and Operating Practices Subcommittee, and the Remedial Action Scheme Reliability Task Force. APS is active on many of these committees.

Regional joint planning efforts also have been undertaken through groups such as the Western Area Transmission Systems technical studies task force, which addressed the

Arizona/California/Nevada region. Also, the Four Corners technical studies task force addressed the Arizona/New Mexico/Utah/Colorado region. The Southwest Regional Transmission Association worked with utilities from West Texas, New Mexico, Arizona, Nevada, and Southern California. More recently, the Southwest Transmission Expansion Plan group has been established to study the Arizona/California/Nevada region's needs, including the Palo Verde to Devers II project. Again, APS has been an active participant in these studies.

Within Arizona, APS' joint planning efforts have been focused in groups such as WAPA's Joint Planning Agreement activities, the Central Arizona Transmission study group, and involvement in the Commission's Biennial Transmission Assessments. Local evaluations involving APS have resulted in the Company working with other utilities in areas such as Yuma, Casa Grande, Phoenix, and Douglas as well as in many other locations and with tribal utilities.

The joint planning activities discussed above have led to many significant joint participation projects involving APS. Three power plants are jointly owned by APS and other utilities, with the Palo Verde Nuclear Generating Station being the largest. The other jointly-owned plants are the Four Corners Power Plant and the Navajo Generating Station. In addition, the Yucca, Cholla, West Phoenix and Saguaro Power Plants include generation owned by non-APS participants on site.

With respect to transmission, there are 11 extra high-voltage lines in Arizona in which APS is a joint participant:

- Navajo-Westwing 500kV
- Navajo-Moenkopi 500kV
- Moenkopi-Yavapai 500kV
- Yavapai-Westwing 500kV
- Palo Verde-Westwing #1 500kV
- Palo Verde-Westwing #2 500kV
- Palo Verde-Rudd 500kV
- Hassayampa-Jojoba 500kV
- Jojoba-Kyrene 500kV
- Hassayampa-North Gila 500kV
- Perkins-Mead 500kV

In addition to these transmission lines, there are numerous instances where facilities share towers, poles, rights of way and easements with other utilities and districts. APS is continuing to pursue joint projects to further develop the transmission system, including the Palo Verde-Southeast Valley 500 kV project.

Joint transmission planning, joint project development, and the shared use of rights of way or facilities where appropriate has been a policy supported by both Staff and the Commission. These joint efforts allow for a more robust and more economical bulk-power system and for the construction of transmission projects that would be more difficult or potentially not practical if only a single utility was involved. Joint projects also do so while reducing the environmental impacts of the facilities. It is a policy that APS believes appropriate in today's changing electricity marketplace and that APS will continue to pursue.

Interconnection Procedures and Generator Interconnections

APS has implemented interconnection procedures to make it easier for other companies to request interconnection service. APS was one of the first five utilities in the United States to use a pro-forma interconnection process and has adopted a standard Interconnection and Operating Agreement and interconnection procedures that have been approved by FERC.[21] Additionally, APS has helped develop interconnection procedures for the Navajo Project, Palo Verde, Hassayampa Switchyard and for the Mead-Phoenix Project. These procedures have helped take the uncertainty out of interconnections to these facilities, and facilitated such interconnections. Also, APS spent a great deal of time at FERC and with other market participants to develop a Standardized Generator Interconnection Agreement and Procedures in 2002, which ultimately resulted in a Notice of Proposed Rulemaking ("NOPR") on the subject in FERC Docket No. RM02-1.

APS has been proactive in working with, rather than against, generators on interconnection issues. For example, APS worked aggressively to site and then construct the Panda Gila River Interconnection Project, which consisted of two 500 kV transmission lines from Gila Bend to the Palo Verde–Kyrene 500 kV transmission line. Because the project crossed federal land, APS completed an Environmental Assessment with the Bureau of Land Management, and in nearly record time received a Finding of No Significant Impact from that agency. APS also constructed the project within the timeline required for the Panda Gila River power plant.

In the case of the interconnection of Reliant's Desert Basin Power Plant, APS interconnected the plant and upgraded APS' transmission system back to the Valley to accommodate Reliant's request for transmission capacity to reach the Valley or the Palo Verde Switchyard. APS did this in a timely manner that facilitated Desert Basin's schedule for construction and start-up.

Hassayampa Switchyard and the Common Bus Concept

One accomplishment that APS believes was very important to generators interconnecting to the Valley transmission system was the groundbreaking development of the common bus concept at the Hassayampa Switchyard. The Hassayampa Switchyard originally was proposed as a "satellite" switchyard to accommodate a large number of generation and transmission interconnections that could not connect to the Palo Verde Switchyard due to lack of space. Because Palo Verde is one of the largest market hubs in the Western United States, many generators desired a direct interconnection of their plants, which would allow a generator to deliver output to the market without having to pay transmission wheeling charges.

APS worked with Salt River Project and the other Palo Verde Switchyard owners to "extend" the Palo Verde Switchyard to the Hassayampa Switchyard by creating a "common

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21 Attachments M and N to APS' OATT.

bus." By constructing such a "common bus," a generator interconnecting at Hassayampa is, in effect, treated as though it is interconnected at Palo Verde and therefore does not have to pay any additional transmission wheeling to move between the Palo Verde Switchyard and the Hassayampa Switchyard.

APS was a principal contributor in securing FERC approval of the novel "common bus" concept. The approval of this concept was combined with an express recognition from FERC for the innovative solution in aiding the wholesale market in the West. FERC also made it a point to state that the concept went beyond what was envisioned in FERC Order 888:

> [D]esignating the current Palo Verde Switchyard as a single point of receipt goes beyond what the Commission envisioned in Order No. 888, yet is, nonetheless, consistent with or superior to the pro forma tariff.... Because numerous market participants' generation will be interconnected to the common bus facility, this single point of interconnection...should become a major regional trading hub. Moreover, this expansion of the common bus designation will help alleviate short-run shortages and promote competition in the Western markets, which is consistent with our Western Markets Order to remove obstacles to increased electric generation in the Western United States.[22]

Regional Interconnection and Reserve Sharing

Finally, APS has taken an active role in developing increased regional interconnection and in reserve sharing. The Southwest Reserve Sharing Group ("SRSG") allows for sharing of contingency reserves among participants to realize more efficient and economic power system operations while maintaining the reliability of the interconnected system. Twelve load serving entities participate in the SRSG. APS is closely involved in the operation of SRSG and an APS employee chairs the SRSG Operating Committee.

Recently, SRSG authorized Duke Arlington Valley to join the group and both Panda Gila River and Mirant have applications pending. Although the original purpose of the group was to provide for reserve sharing among traditional load serving utilities, expanding the membership to include merchant generators could allow them to carry fewer reserves on their own. Thus, it provides a way to "firm" some of their power sales in a more economical way, and fosters the development of a competitive wholesale market.

F. The California and Western Energy "Crisis" and FERC Investigations

Although in 1999 the focus of electric restructuring was directed at retail direct access, the experience of California in 2000 and 2001 abruptly placed wholesale markets at center stage. Due to the interconnected nature of the Western United States' electric grid, this "crisis" extended far beyond the borders of California and is an important backdrop for considering actions taken by APS and its affiliate, PWEC, during this period.

22 *Arizona Public Service Co., et al.*, 96 FERC ¶ 61,156 (2001).

The Western Energy Crisis

The West experienced unusually high electricity prices during 2000 and 2001. High natural gas prices from the summer of 2000 through the winter of 2000-2001, in combination with accelerated electric demand, generation failures, flawed regulation and transmission constraints combined to create these extraordinary wholesale electric prices. To make matters worse, from June through August 2000, California experienced one of the hottest summers in 106 years of record-keeping. Then, in November, average temperatures were unusually low.

This atypical weather helped drive load growth as temperature-sensitive customers increased their demand. Low snow pack from the winter and lower rainfall in the summer of 2000 reduced western area hydropower output. Specifically for California, the state's market design, which relied on the spot market for much of its needs, and the lack of demand response and under-scheduling of load by the major California investor-owned utilities exacerbated the problem. Finally, the forced divestiture of generation left California utilities without any backstop to high wholesale prices. By September 2000, the state's three investor-owned utilities had deferred more than $3 billion in wholesale power costs. By November 2000, the same utilities had deferred $6 billion of wholesale power costs because they were precluded from passing such costs through to ratepayers. By January 2001, both Southern California Edison and PG&E were downgraded to junk status by the major credit ratings agencies and one, PG&E, was forced into bankruptcy.

The backlash of two bad years in California began to play out politically. In early 2001, the California legislature stepped in to authorize the California Department of Water Resources ("CDWR"), rather than the cash- and credit-strapped utilities, to make power purchases. By June, CDWR had entered into about $43 billion worth of long-term energy contracts in an effort to stabilize the energy crisis in the state. It also purchased more than $10 billion of wholesale energy on the spot and day-ahead markets. A subsequent report by the California Auditor General summarized the circumstances surrounding the execution of long-term contracts by CDWR:

> Forced to act quickly to restore stability to the State's electrical power system during the California energy crisis of 2000 and 2001, the Department of Water Resources...entered into a number of long-term contracts for electricity, many of which later proved to be unfavorable to the State.[23]

That same report notes that CDWR likely will be responsible for managing the portfolio of long-term contracts for "much of the next decade."

As another California Auditor General's report noted, "CDWR's capabilities were dwarfed by the magnitude of its mission under the power purchasing programs."[24] By early 2002, however, California agencies had filed complaints with FERC to void these contracts, alleging that they were entered into at a time when power producers were manipulating the

[23] Bureau of State Audits, California Energy Markets, Report No. 2002-009 (April 2003).

[24] Bureau of State Audits, California Energy Markets, Report No. 2001-009 (December 2001).

market. The state continues to both renegotiate and, as part of the investigations discussed below, litigate the long-term contracts that it entered into in 2001.

Western Markets Investigations

Investigations into the Western energy crisis are continuing at FERC. Investigations have been initiated into the California and the Northwest markets and a West-wide probe into the distortion in the electric and natural gas markets after the collapse and subsequent admissions of market manipulation by Enron. These proceedings are discussed below.

Due to their load-serving obligations, particularly during the volatile markets of the time, APS and its affiliates often purchased blocks of energy to meet load requirements and sold any excess into Western spot markets, including those in California. On balance, APS and its affiliates were buyers in the California markets and are owed a net of several millions of dollars in refunds under the proposed findings of the administrative law judge in the California refund investigations at FERC. Further, APS and its affiliates entered into contracts with other Western entities to buy and sell energy throughout this period.

For the California markets, in *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and California Power Exchange*, Docket Nos. EL00-95-000, et al., a number of parties purchasing energy in markets operated by the California Independent System Operator ("CAISO") or the California Power Exchange have asserted that the prices they paid for such energy were unjust and unreasonable under the Federal Power Act and that refunds should be made in connection with sales into those markets from October 2, 2000 through June 20, 2001. APS supplied energy to these markets during this period, and has been an active participant in the proceedings.

In orders issued on November 1, 2000, December 15, 2000, June 19, 2001, July 25, 2001 and December 19, 2001, FERC concluded that the electric market structure and market rules for wholesale sales of energy in California were flawed and, in conjunction with an imbalance of supply and demand, have caused unjust and unreasonable rates for short-term energy under certain conditions. FERC ordered various modifications to the market structure and rules in California and also established a fact-finding hearing before an administrative law judge to calculate refunds for spot market transactions in California.

FERC directed the administrative law judge to make findings of fact with respect to: (1) the mitigated price in each hour of the refund period; (2) the amount of refunds owed by each supplier according to the methodology established; and (3) the amount currently owed to each supplier (with separate quantities due from each entity) by the CAISO, the California Power Exchange, the investor-owned utilities, and the State of California.

APS was a seller and a purchaser in the California markets at issue in this proceeding, and to the extent that refunds are ordered, APS should be a recipient as well as a payor of such amounts. On December 12, 2002, Presiding Administrative Law Judge Bruce Birchman issued Proposed Findings of Fact with respect to the refunds. The Proposed Findings of Fact include a "ballpark summary" of amounts owed to and amounts owing from each supplier in the CAISO and California Power Exchange markets. Under the judge's preliminary calculations, APS is owed over $5 million in refunds. In March 2003, FERC issued an order accepting the great majority of the Proposed Findings of Fact, but revised the refund calculations to allow additional refunds based upon an adjustment in natural gas pricing. Final refund amounts will not be established until the appropriate adjustment to the natural gas pricing is determined, an issue still pending on rehearing at FERC.

On November 20, 2002, FERC reopened discovery in these proceedings pursuant to instructions of the U. S. Court of Appeals for the Ninth Circuit that FERC permit parties to adduce additional evidence of potential market manipulation for the period January 1, 2000, through June 20, 2001. Discovery was open until February 28, 2003, at which time parties submitted additional evidence and proposed findings. Action on these findings is still pending at FERC.

For the Pacific Northwest markets, in *Puget Sound Energy Inc., et al.,* Docket No. EL00-10, et al., FERC ordered a preliminary evidentiary hearing to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period beginning December 25, 2000 through June 20, 2001. FERC required that the record establish the volume of the transactions, the identification of the net sellers and net buyers, the price and terms and conditions of the sales contracts, and the extent of potential refunds. APS supplied energy to the Pacific Northwest markets during this period, and has been an active participant in these proceedings as well.

On September 24, 2001, Presiding Administrative Law Judge Carmen Cintron concluded that prices in the Pacific Northwest during the period December 25, 2000 through June 20, 2001 were the result of a number of factors in addition to price signals from the California markets, including the shortage of supply, excess demand, drought, and increased natural gas prices. Under these circumstances, the Judge ultimately concluded that the prices in the Pacific Northwest were not unreasonable or unjust and refunds should not be ordered in this proceeding. FERC is currently reviewing the Judge's Report and Recommendations.

On December 19, 2002, FERC opened a new discovery period, through February 28, 2003, to permit the parties to adduce additional evidence for the period January 1, 2000, through June 21, 2001. Parties filed evidence and proposed findings for FERC's review in conjunction with the proposed findings of Judge Cintron. Action on these findings is still pending at FERC.

FERC also has launched an investigation of price manipulation in the western markets. The FERC's Staff issued a final report on the investigation in March 2003. FERC continues to consider the Staff recommendations and review additional information gathered on this topic.

G. The Commission's Inquiry Into the Electric Competition Rules

APS and Pinnacle West did not watch events develop in California and the Western United States without evaluating their potential impact on Arizona. Much like the California utilities, APS was in a potentially precarious position as electric restructuring began to be implemented. Specifically, APS was short of needed capacity and was not able to construct new capacity itself due to the divestiture requirements in Rule 1615 and its retail Code of Conduct. Also, APS was subject to a rate reduction schedule in its 1999 Settlement that restricted the Company's ability to pass wholesale power costs through to customers if they were to increase significantly.

Indeed, one of the shortcomings in the 1999 Electric Competition Rules was that incumbent utilities such as APS retained the obligation to serve customers—even those returning from competing generation suppliers—with reliable and reasonably-priced service, but due to the divestiture requirement were prohibited from constructing generation to meet that obligation. Thus, to meet APS' growing electric load and to ensure reliability for APS Standard Offer customers, Pinnacle West embarked upon a two-pronged effort. First, Marketing and Trading entered into a series of arrangements (both financial and physical) to manage wholesale electric and natural gas market price risk and reliability until such time actual generation plants could come on-line to perform the same function in a longer-term and more stable manner. Secondly, PWEC began and completed all the activities to construct approximately 1,700 MW of new generation that serves APS' customers today.[25]

To obtain permanent financing for the more than $1 billion in new PWEC investment, PWEC and Pinnacle West relied on the Commission's assurance that PWEC would receive the existing APS generation assets. Accordingly, Pinnacle West provided interim financing through a series of short-term bridge loans. And, despite the later opportunity during the California energy crisis to sell the output of the new PWEC units forward in that lucrative market, it was held back for future use by APS customers.

Throughout this period, APS kept the Commission informed of its concerns. By autumn 2001, APS had concluded that wholesale power markets were too volatile to support implementation of the competitive bidding and wholesale procurement plan required by Rule 1606(B). Under that rule, starting in January 2003 and following the divestiture of the APS generation, APS would have to look to the wholesale market for all of its Standard Offer power needs, with at least 50 percent coming through some sort of competitive bidding process. Given the failures in the wholesale markets in 2000 and 2001, APS negotiated a proposed purchase power agreement involving PWEC that would require PWEC to meet APS' full requirements at cost-based rates, and would include a more modest competitive bidding component. This proposal would have allowed the APS generation to be divested, thus satisfying that requirement of the Electric Competition Rules, while still providing for some competitive bidding for wholesale supply.

Because the proposed agreement would not meet the literal requirements of Rule 1606(B), APS filed its Request for Partial Variance with the Commission on October 18, 2001. In that filing, APS requested that the Commission approve the proposed purchase power agreement and grant a partial variance to Rule 1606(B) to allow APS to implement the

[25] This capacity figure does not include temporary generation installed in the Summer of 2001 by PWEC at a cost of approximately $30 million.

agreement. APS made it clear, however, that if the Commission disagreed with its application the Company would proceed with "good faith compliance with Rule 1606(B) as written."[26]

Also in late 2001, APS took note that retail competition in Arizona was not developing due at least in part to the California energy crisis. Skyrocketing and volatile wholesale prices also made it impractical for ESPs to compete in Arizona against fixed or declining Standard Offer rates. And, the demise of retail competition in California and Nevada, and its delay in New Mexico, reduced Arizona to a "stand-alone" play for ESPs in the Desert Southwest, and many left the state or went out of business. Additionally, the Electric Competition Rules were found unconstitutional by a trial court judge, and are still on appeal with the Arizona Court of Appeals.

In December 2001, then-Chairman Mundell filed a letter with the Commission's docket control requesting that parties respond to a series of questions on general issues relating to electric restructuring in Arizona. On January 22, 2002 a generic docket on electric restructuring was opened. On April 25, 2002, at a Special Open Meeting, the Commission stayed indefinitely the scheduled hearing on APS' Request for Partial Variance. Instead, it ordered that certain issues relating to electric restructuring be addressed through the generic docket and a hearing on a wide variety of issues was held in June 2002.

After the hearings, the Commission issued Decision No. 65154 resolving so-called "Track A" issues. In the Track A Decision, the Commission in part ordered APS to cancel any plans to divest generation, stayed Rule 1606(B), and ordered APS to file a modified Code of Conduct. In the Track A decision, the Commission noted:

> In retrospect, it was a good idea to delay divestiture and competitive procurement in the APS and TEP Settlement Agreements, given what has happened in the last two or so years, including the experience in California; the market volatility and illiquidity; and the lack of public confidence in the transition to electric deregulation and the ability of regulators to prevent price spikes, ensure reliable service, and prevent bankruptcies.[27]

In staying Rule 1606(B), the Commission directed that competitive solicitation requirements be developed in a "Track B" proceeding. The Commission specifically stated in its Track A decision that Rule 1606(B) and the divestiture requirements of Rule 1615 were inextricably linked.[28] Although the Commission completely suspended divestiture, it nonetheless ordered APS in the Track B proceeding to competitively solicit for substantially more than the Company's net short capacity and energy requirements, and to include in addition economy energy and reliability must run generation. The Track A order, however, did not address the transitional implications to Pinnacle West and its affiliates of the Commission's changes to the

[26] *See* APS' April 19, 2002 Motion for Threshold Determination, Docket No. E-00000A-02-0051, et al., at 3.

[27] Decision No. 65154 at 22.

[28] *Id.* at 24.

1999 Settlement or the significant costs APS incurred in compliance with and reliance on that Settlement.[29]

[29] APS appealed the Track A Decision to the Maricopa County Superior Court and Arizona Court of Appeals. While those appeals are still pending, APS and Staff agreed to Principles of Resolution on December 13, 2002. The Principles of Resolution narrow APS' claims in the Track A appeals and will provide the Commission with the opportunity to address the remaining claims in the Company's upcoming rate case.

IV. COMPLIANCE WITH ISSUES RAISED

A. Electric Competition Rules

In Section III, this Report discusses from an overall perspective the Company's and its affiliates' compliance with the Electric Competition Rules. This section focuses on those compliance efforts through the principal requirements of the specific Electric Competition Rules that apply.

Rule 1602. Rule 1602 provides that customers will be eligible for competition pursuant to the phase-in schedule in Rule 1604, and prohibits an Affected Utility's ESP affiliate from providing services in any other Affected Utility's service area until its affiliated utility has commenced direct access. Pursuant to Rules 1602 and 1604 and Decision No. 61973, customers in APS' service territory were eligible for competition on July 1, 1999. Also, APS' competitive ESP affiliate, APSES, did not provide service in another Affected Utility's service territory until APS' service territory was open for competition.

Rule 1603. This rule outlines the requirements for an ESP to obtain a competitive CC&N. In addition to standard filing requirements, this rule directs Affected Utilities to negotiate in good faith in developing Service Acquisition Agreements between the utility and an ESP. APS' competitive ESP affiliate, APSES, obtained a CC&N in Decision No. 61669 (April 21, 1999) in which the Commission determined that it had complied with the requirements of this rule. Also, APS was the first Affected Utility to develop and have approved an ESP Service Acquisition Agreement and negotiated its agreements with ESPs in good faith. That Service Acquisition Agreement was used by Staff as a template for the development of agreements by other Affected Utilities.

Rule 1604. Rule 1604 sets forth the phase-in for direct access. The initial date to commence the phase-in would be established for each Affected Utility, but all customers were to be eligible for direct access no later than January 1, 2001. Also, Affected Utilities were directed to file residential phase-in programs and file quarterly reports. Utilities were also to file a report detailing possible mechanisms to provide benefits, including rate reductions of 3 to 5 percent, for all Standard Offer customers.

APS commenced its phase-in as of July 1, 1999, the date specified in Decision No. 61973. The initial amount of commercial and industrial load that was eligible was 653 MW. APS filed its Residential Phase-In Program on September 15, 1998 and received Staff approval of that program on October 19, 1998. The Company submitted a revised Residential Phase-In Program on December 21, 1998 pursuant to Decision No. 61272. That revised program reflected changes in the rules that increased the number of residential customers eligible for direct access. APS filed its initial Quarterly Report with the Commission on February 15, 2000, covering October through December 1999. This report identified all of the customer education meetings presented by APS, bill stuffers regarding competition, and special customer mailings on retail direct access. APS' final report pursuant to this rule was filed on February 14, 2003 for 2002.

Finally, the mechanism to provide benefits to Standard Offer customers was included in the 1999 Settlement. In the 1999 Settlement, APS provided rate reductions to Standard Offer customers totaling 7.5 percent by July 2003, rather than the 3 to 5 percent suggested in the rule.

Rule 1605. This rule requires an entity providing Competitive Services to obtain a CC&N, and that certificated ESPs may offer services under bilateral or multilateral contracts with retail consumers. As noted above, APSES was certificated to provide Competitive Services, and offered such services under bilateral and multilateral contracts with retail consumers.

Rule 1606. This rule specifies services that must be made available under retail electric competition. Rule 1606(A) requires Affected Utilities to make Standard Offer service and Noncompetitive Services available at regulated rates. It also requires that after an Affected Utility divests its generation, it will be required to act as the Provider of Last Resort in its service area. Rule 1606(B) had required Utility Distribution Companies, post-divestiture, to obtain their generation from the wholesale market through prudent arm's-length transactions with at least 50 percent through a competitive bid. Rule 1606(C) includes requirements for Standard Offer tariffs, while Rule 1606(D) addresses Noncompetitive Services (also called direct access) tariffs. Other provisions of Rule 1606 require Affected Utilities to accept power and energy delivered by an ESP to their systems for delivery to the ESP's customers, and for the provision of consumer data by the utility to ESPs.

Pursuant to Rule 1606(A), APS made available Standard Offer and Noncompetitive Services at regulated rates when its service territory was opened to competition. Rule 1606(B) was never in effect for APS, as it was stayed until January 1, 2003 by Decision No. 61973 and subsequently indefinitely stayed by the Commission's Track A Decision.[30]

As to the other requirements of Rule 1606, APS filed and the Commission accepted Standard Offer tariffs and unbundled direct access tariffs. Standard Offer and direct access tariffs were filed by APS on September 29, 1999 and were approved on November 10, 1999 with an effective date of October 1, 1999. In July 2000, APS began including an additional page with each customer's bill to identify "Competitive Services" and "APS Delivery Service Information," showing the calculated price for each service based on the customer's usage. This page was intended to allow customers to compare their Standard Offer rates with potential rates from competitive ESPs.

APS also made arrangements to accept power and energy delivered to APS' distribution system by other Load Serving Entities, and APS made the process for making such deliveries more commercially reasonable for ESPs by helping to form the AISA and then adopting the AISA protocols that allowed ESPs to supply their generation from Palo Verde rather than pro rata across APS' various transmission delivery points. Finally, APS provided ESPs with the

[30] APS had requested a partial variance to Rule 1606(B) through a filing made in October 2001, over a year prior to the date that the rule was supposed to take effect for APS. Although now rendered moot by the Track A decision, APS clearly stated in that proceeding that if the Commission denied the Company's Request for Partial Variance, APS would implement Rule 1606(B) as written and divest its power plants to PWEC as required by the 1999 Settlement and Rule 1615. *See* APS' April 19, 2002 Motion for Threshold Determination, Docket No. E-00000A-02-0051, et al., at 3.

consumer data as required by this rule. The ESP Service Acquisition Agreement that APS developed was approved by Staff on August 2, 1999, and APS' Schedule 10, Terms and Conditions for Direct Access, was approved in Decision No. 61270 (December 2, 1998).

Rule 1607. This rule provides that Affected Utilities were to be entitled to recover *all* of their stranded costs, although they were expected to mitigate or offset such costs by reducing costs, expanding wholesale or retail markets, or offering a wider scope of permitted utility services for profit. The rule provided that Affected Utilities would file stranded cost estimates and, following a hearing, the Commission would approve mechanisms for stranded cost recovery.

The Commission acknowledged in Decision No. 61973 that APS had at least $533 million net present value of stranded costs. Although the rule entitled APS to fully recover those stranded costs, APS agreed to write down $234 million of prudently incurred costs in the 1999 Settlement. The 1999 Settlement constituted APS' compliance with the stranded cost filing requirement in Rule 1607. The 1999 Settlement also addressed the various mechanisms identified in this rule.

Rule 1608. This rule provides that each utility shall file for a Systems Benefit Charge to collect system benefits costs from all customers. APS has a system benefits charge in place pursuant to this rule, although the EEASE fund was eliminated in Decision 59601 (April 24, 1996). Amounts collected through the System Benefits Charge are applied by APS to the Commission's Environmental Portfolio Standard.

Rule 1609. Rule 1609 includes a number of provisions relating to transmission and distribution access. Rule 1609(A) and (B) require Affected Utilities to provide open access to their transmission and distribution systems, but to retain the obligation to ensure that these systems are adequate to serve the utility's customers. Rule 1609(C)-(G) set forth the Commission's support for the formation of an RTO and the AISA, and provide requirements relating to the formation of those entities. Rule 1609(H) addresses the use of scheduling coordinators to aggregate customers' schedules. Rule 1609(I) addresses cost-sharing for must-run services and requires the AISA to develop protocols regarding must-run services. Finally, Rule 1609(J) provides that statewide settlement practices be adopted.

APS has provided for non-discriminatory open access to its transmission and distribution systems to allow ESPs to reach APS retail wires customers. As discussed above, APS helped develop and implemented the AISA protocols to make such access easier for ESPs seeking to serve APS load. APS has also provided for adequate distribution and transmission import capability and has not had an outage or curtailment related to a lack of transmission import capacity since the rules were adopted.

APS has been active in supporting the AISA and adopting the resulting protocols pursuant to Rule 1609(D). APS has now focused its efforts on forming the WestConnect RTO, as required by Rule 1609(F). Must-run protocols have been developed to ensure that must-run services are available to ESPs if necessary. Finally, APS has developed a fair and reasonable generation settlement process pursuant to Rule 1609(J).

Rule 1610. This rule requires in-state reciprocity for Public Power Entities (primarily Salt River Project and a few cities) and other non-jurisdictional electric utilities (primarily special purpose districts). It is not directly applicable to APS.

Rule 1611. Rule 1611 discusses rates that can be charged by ESPs for Competitive Services and the filing of contracts with the Commission's Staff. APSES has competitive rates on file with the Commission that were approved when its CC&N was granted.

Rule 1612. Rule 1612 includes a number of provisions relating generally to service quality, consumer protection, safety, and billing requirements. APS complies with all of the requirements in this rule, and has implemented practices to ensure that the rules are carried out. For example, Rule 1612(D) provides that a residential customer shall have the right to rescind its authorization to change providers of any service within 3 business days by providing written notice. APS has developed its direct access systems to specifically recognize, support and track this requirement. Additionally, APS has been very active in the Commission's Process Standardization Working Group, which is streamlining many of the requirements in this and other rules.

Rule 1613. This rule sets forth various reporting requirements, information to be contained in the reports, and a reporting schedule. APS and APSES have each submitted the reports required by this rule. APS filed its initial semi-annual Retail Electric Competition Report with Staff on April 17, 2000 and filed its most recent report on April 15, 2003. Also, pursuant to Decision No. 64810, APS filed its initial report for Estimates on First and Final Bills on April 15, 2003 and will continue to file such reports semi-annually with Staff.

Rule 1614. This rule sets forth certain administrative requirements. Rule 1614(A) provides that ESPs may file additional tariffs with the Commission. Rule 1614(B) provides that contracts filed under the rules shall not be open to public inspection except on order of the Commission. Rule 1614(C) provides that parties may request variations or exemptions from the terms or requirements of *any* of the rules. This was the authority that supported APS' October 2001 Request for Partial Variance to Rule 1606(B). Finally, Rule 1614(D) and (E) provide for dispute resolution (which has never been invoked against APS) and requires Staff to implement a customer education program, respectively.

Rule 1615. Rule 1615(A) required the separation of "all competitive generation assets and competitive services" by January 1, 2001. Pursuant to Decision No. 61973 and the 1999 Settlement, APS was granted an extension of that deadline until January 1, 2003. Although the rule uses the term "competitive generation assets," the Concise Explanatory Statement that accompanies the rule explains that it is "clear that competitive generation includes all generation except for Must-Run Generating Units."[31] Moreover, the 1999 Settlement specifically listed the generation that APS was required to divest, and it included *all* generation, including generation that at times would be considered as Must-Run Generating Units. APS has not otherwise

[31] Decision No. 61969 at 60. This also supports why it was reasonable for APS to assume that any new generation constructed at APS after the rules were adopted would be considered a "competitive service" even if used to supply "non-competitive" Standard Offer customers. That was clearly the position of the Commission at the time the rules were adopted.

provided Competitive Services after the effective date of the rule. Such services are instead provided through APSES.

Rule 1616. This rule sets forth the requirements for a Code of Conduct between Affected Utilities and subsidiaries that will offer Competitive Services as a competitive electric affiliate. The rule requires such Codes of Conduct to address nine enumerated subjects. APS filed and the Commission approved a Code of Conduct in Decision No. 62416. That decision concluded as a matter of law that the Code of Conduct met the requirements of Rule 1616 and Decision No. 61973.

Rule 1617. Rule 1617 addresses the disclosure of information through a consumer information label. APS participated in the Consumer Education Working Group to formulate a standard disclosure label which provides customers with information to assist them in choosing an electric supplier. The label for APS is posted on the Company's Web site, is provided to all new customers, and is provided to existing customers upon request. Additionally, APS includes with each customer bill a second page that reflects billing and cost information to allow customers to compare APS' Standard Offer service with competitive offers. The APS customer information label is provided in the various Electric Competition Reports that APS submits pursuant to the rules.

B. Decision No. 61973

Decision No. 61973 approved the 1999 Settlement. Although many of the provisions in that agreement were changed by the Commission, APS has continued to comply with its obligations under the 1999 Settlement. That compliance is generally discussed below.

General Obligations of the Settlement

The 1999 Settlement provided for the implementation of retail direct access in APS' service territory. Pursuant to the requirements in that agreement, APS opened its service territory to competition, and allowed its previously exclusive CC&N to be modified to permit retail access.

Rate matters were also addressed in the 1999 Settlement, and APS filed unbundled direct access rates with its Commission filing of the Settlement. Those rates were revised to reflect metering, meter reading and billing credits and were submitted with the Addendum to the Settlement Agreement. The Commission approved the Company's unbundled rates in Decision No. 62035 (November 10, 1999). APS also reduced Standard Offer and direct access rates in the amounts required by the Settlement, which, following the July 1, 2003 reduction, will result in a 7.5 percent rate reduction for residential Standard Offer customers since the Settlement was approved. Those rate reductions will have saved APS customers more than $400 million through June 30, 2004.

The Settlement also required APS to file and the Commission to approve adjustment clauses to provide for full and timely recovery beginning July 1, 2004 of certain reasonable and prudent costs in four categories—meeting Standard Offer obligations, costs associated with customers returning from direct access to Standard Offer service, compliance costs associated with the Electric Competition Rules, and future Commission-approved system benefits programs. APS timely filed its application for such adjustment clauses on May 31, 2002. APS also agreed at the request of Staff to extend the December 31, 2002 date required in the Settlement for the Commission to approve the adjustment clauses. APS will also, pursuant to the Settlement, file a general rate case with prefiled testimony prior to June 30, 2003.

Additionally, the 1999 Settlement addressed stranded cost recovery. Under the Settlement, APS agreed to write off $234 million of allowable and prudently-incurred costs. As required, APS wrote off that amount on its accounting books.

APS also had agreed in the 1999 Settlement to not recover one-third of the costs associated with the transfer of the APS generation to an affiliate. The Commission explained that its rationale for reducing the amount of transfer costs that could be deferred and recovered by APS was because "the Company is making a business decision to transfer the generation to an affiliate instead of an unrelated third party."[32]

Corporate Restructuring and Divestiture

The original Settlement provided that APS would form an affiliate to receive the APS generation assets that were required to be divested by the Electric Competition Rules and the Settlement. Based on comments by intervenors, this original language was revised to make explicit that the generation affiliate would be formed as a subsidiary of Pinnacle West, not of APS. APSES, which is the retail ESP affiliate of APS, had already been formed as a subsidiary of Pinnacle West. It received a CC&N from the Commission in Decision No. 61669 (April 21, 1999). PWEC was formed after the Settlement was approved as the affiliate to receive the APS generation assets. The decision approving the 1999 Settlement found that the formation of a generation affiliate (PWEC) was in the public interest. The approval also affirmed that APS would purchase from its generation affiliate at market based rates and that such purchases were in the public interest. As discussed in more detail below, APS has purchased from PWEC and Pinnacle West under those parties' market based rate tariffs.[33]

APS began implementing, almost immediately after the Settlement was approved, the process necessary to transfer the APS generation to PWEC within the two-year extension granted by the Commission. The generation assets that were to be transferred under Decision No. 61973 included all of APS' generation units (other than solar and distributed generation), including Must-Run Generation Units.[34] APS filed for Nuclear Regulatory Commission approval for license transfers and for FERC approval for the transfers. APS also initiated discussions with other regulatory agencies, such as the Arizona Department of Environmental Quality, for the transfer of permits. And, filings were made with the Internal Revenue Service to confirm the tax implication of the transfers.

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[32] Decision No. 61973 at 10.

[33] *See id.* at Attachment 1, § 4.1.

[34] *See id.* at Exh. C.

In connection with the restructuring, the Commission granted Pinnacle West certain waivers of the Affiliated Interest Rules, A.A.C. R14-2-801, *et seq.* Although APS and Pinnacle West remained subject to other requirements of the Affiliated Interest rules, Pinnacle West was granted a wavier of Rule 801(5) and Rule 803, which address organization and reorganization of holding companies, to the extent that a reorganization did not directly involve APS. Essentially, this waiver allowed Pinnacle West to reorganize, form, buy or sell non-Utility Distribution Company affiliates and acquire or divest interests in non-Utility Distribution Company affiliates, without Commission approval. Also, Rule 805(A), which requires annual reports of diversification activities and plans, was limited to apply only to APS. Finally, the decision granted a waiver to APS and its affiliates from annual reporting requirements relating to five categories of information under Rule 805(A). The Commission concluded that these waivers were in the public interest and granted them in Decision No. 61973. In Decision No. 65796, however, the Commission revoked waivers granted in the 1999 Settlement during the term of the PWEC loan approved in that decision.

Other Obligations

The Settlement also provided that APS would withdraw its litigation challenging the Electric Competition Rules and stranded cost decisions when Decision No. 61973 was final and no longer subject to appeal. APS dismissed its appeals on January 11, 2002, after the Arizona Supreme Court affirmed the Commission's decision and the 1999 Settlement, holding that the Settlement was a valid and binding obligation of the Commission.

Finally, the Settlement contained a number of miscellaneous provisions, each of which APS has honored. The Company has continued to support funding of the Arizona Community Action Partnership and continues its low income rates under their current terms and conditions. Also, APS has actively supported the AISA and adopted AISA protocols. And, APS filed its interim proposed Code of Conduct within 10 days of approval of the 1999 Settlement.

Supply of Generation

One of the requirements in the 1999 Settlement that was added in the November 24, 1999 addendum was that APS file an initial proposed Code of Conduct that would include a provision to govern the supply of generation during the two-year extension granted for both divestiture and compliance with Rule 1606(B) to ensure that APS did not "give itself an undue advantage over the ESPs."[35] On October 28, 1999 APS filed an initial proposed Code of Conduct which contained the following provision:

> Prior to the divestiture of APS generation pursuant to [Decision No. 61973], APS generation will not be sold on a discounted basis to Standard Offer customers without the express permission of the [Commission].

Both the language approving the Settlement and the comments filed by Enron to that proposed Code of Conduct illustrate that the issue regarding "the supply of generation" was not

[35] Decision No. 61973 at 12.

how APS would procure power from other suppliers, but rather how APS would use the generation that it still controlled.[36] For example, Enron agreed that the APS proposal restricting discounts to Standard Offer service was appropriate. But Enron argued that the Code of Conduct should address "how APS will *dispose* of excess capacity" and whether APS would "willingly *sell* excess capacity in the open marketplace" or whether APS should "be required to *sell* excess power to the highest bidder."[37] New West Energy, which was an ESP, filed comments supporting the Code of Conduct as filed by APS. The Arizona Transmission Dependent Utilities Group filed comments but did not address this issue. No other parties, apart from Staff, commented on the proposed Code of Conduct.

Staff filed testimony opposing the Code of Conduct filed by APS and attached to the testimony of its expert witness its own proposed Code of Conduct. Staff's proposed Code of Conduct contained the same language regarding generation supply prior to divestiture as in APS' original proposed Code of Conduct. After a hearing was conducted on the matter, APS met with Staff and reached a stipulated Code of Conduct based on Staff's proposed Code of Conduct that included changes from Staff and intervenors in the case. The two specific recommendations from intervenors that were not accepted, including one from Enron on the language in the "generation supply" provision, were clearly identified for the Commission.

APS' and Staff's Joint Proposed Code of Conduct filed in 2000 contained a provision regarding the supply of APS generation prior to divestiture and the Commission determined that it met the requirements of Decision No. 61973. APS has complied with that Code of Conduct provision and there was never a requirement to address the procurement of generation by APS in the Code of Conduct.

The stipulated APS Code of Conduct, including the language on generation supply that was quoted above, was approved by the Commission in Decision No. 62416. In that decision, the Commission concluded that the Joint Proposed Code of Conduct, as amended by the decision, "satisfies the requirements of A.A.C. R14-2-1616 and Decision No. 61973" and approved the Code of Conduct.

C. APS' Code of Conduct

As explained above, the APS Code of Conduct applies to the conduct of APS and its interaction with its Competitive Retail Electric Affiliate, APSES. Both prior to and upon final approval of the APS Code of Conduct by the Commission, APS took significant and meaningful steps to ensure compliance with the APS Code of Conduct and the Policies and Procedures that implemented the APS Code of Conduct. Specifically, among other activities:

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[36] Comments of Enron Corp. to APS' Proposed Code of Conduct, Docket No. E-01345A-98-0473, et al. (December 3, 1999) at 4-5.

[37] *Id.* at 5 (emphasis added).

- Interim training was provided to key groups prior to the final approval of the APS Code of Conduct by the Commission.

- Upon approval of the APS Code of Conduct, the Pinnacle West Business Practices Department implemented a comprehensive training program for employee groups identified as potentially having significant customer, ESP or public contact. The following key groups were provided training:

  - Call Center
  - Customer Account Management
  - Customer Operations
  - Division Offices
  - Design Project Leaders
  - Economic Development
  - Energy Delivery and Sales
  - Field Collections
  - Marketing
  - Outdoor Lighting
  - Siting
  - Technology Development

- Key leaders and shared services employees that could have significant interface with APS and APSES employees also received training.

- Employees that did not need the more comprehensive training were provided notice of the Commission Rules, the APS Code of Conduct and the Policies & Procedures through intra-company articles and were invited to call the Pinnacle West Business Practices Department with any questions.

- Sections on the APS Code of Conduct were added to existing training programs (*e.g.*, Leadership Academy, Survival Skills for Leaders, and Corporate Ethics Policy) and new training such as the on-line *Doing the Right Thing* course.

- APSES was physically separated from APS through a move to a different office building, APSES employees were required to have escorted access to APS facilities, and a separate phone switch was installed.

- Copies of the APS Code of Conduct and the Policies & Procedures were posted on the Pinnacle West Business Practices intranet site, along with copies of the FERC Code of Conduct and FERC Standards of Conduct.

- APS developed and implemented inter-affiliate agreements to govern transactions between affiliates, including APS and APSES. Those agreements required compliance with the APS Code of Conduct.

- The Pinnacle West Audit Services Department conducted periodic audits of compliance with sections of the APS Code of Conduct.

APS and APSES continue to comply with the APS Code of Conduct today, including the recent implementation of additional access restrictions due to the move of certain shared services functions back to APS.[38] And no one has alleged any violation of the APS Code of Conduct by either APS or APSES.

D. Other Applicable Law

1. FERC Requirements

Under the Federal Power Act, FERC has exclusive jurisdiction of most wholesale power and transmission issues. Thus, most of the applicable law relating to wholesale power procurement stems from FERC rules, decisions, or the Federal Power Act itself.

FERC Orders 888 and 2000

In April 1996, in Order No. 888, FERC found that unduly discriminatory and anticompetitive practices existed in the electric industry, and that public utilities that own, control or operate interstate transmission facilities had discriminated against others seeking transmission access.[39] It determined that non-discriminatory open access transmission services, including access to transmission information, and stranded cost recovery were the most critical components of wholesale electricity markets. FERC stated that its goal was to ensure that customers have the benefits of competitively priced generation. Order No. 888 required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to: (1) file open access non-discriminatory transmission tariffs containing certain minimum, non-price terms and conditions; and (2) functionally unbundle wholesale power services from transmission services. APS has an open access transmission tariff on file with FERC and continues to provide non-discriminatory access to its transmission system in accordance with the requirements of Order No. 888.

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[38] Consistent with the Track A Decision, APS submitted a proposed Code of Conduct to the Commission on November 12, 2002. That proposed Code of Conduct is anticipated to be the subject of Commission review later this year.

[39] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part, remanded in part on other grounds sub nom. Transmission Access Policy Study Group, et al. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 122 S. Ct. 1012 (2002).

Order No. 2000, issued in December 1999, encouraged all transmission owners to voluntarily place their transmission facilities in the hands of appropriate RTOs.[40] Order No. 2000 demonstrates FERC's philosophy that, in the longer term, the development of RTOs are superior to functional unbundling in creating independence and preventing undue discrimination. Moreover, FERC stated that there would be no need to enforce standards of conduct separating the transmission system operations and reliability functions and wholesale merchant functions to the extent that the RTO is independent of power marketing interests. In response to this order, APS has been a leader in the formation of the WestConnect RTO.

As discussed above, APS was one of the filing utilities requesting a declaratory order on the WestConnect RTO. On October 10, 2002, FERC, in response to the request for declaratory order, approved significant portions of the WestConnect RTO proposal. WestConnect has been developed to handle security, reservations, scheduling, transmission expansion, planning and congestion management for the Southwest regional transmission system in response to FERC's Order 2000. Its independent board structure will focus on ensuring reliability, nondiscriminatory open-access, and a robust wholesale market. The WestConnect Interim Committee, which APS is chairing, through the Seams Steering Group-Western Interconnection, is working with others in the West to resolve seams issues, which arise where different RTO markets interface.

Transfer of APS Generation to PWEC

As part of the restructuring envisioned by the 1999 Settlement, on July 28, 2000, APS submitted to FERC an application for authorization under Section 203 of the Federal Power Act to transfer all of its fossil and nuclear generation and associated FERC-jurisdictional facilities to PWEC. The filing noted that following the divestiture of generation assets to PWEC, "APS will become a 'wires' company, owning and operating transmission and distribution facilities." On November 24, 2000, FERC issued an order finding that the requested transfer of assets "will not adversely affect competition" and authorized the transaction.

FERC Code of Conduct

A public utility and its affiliates engaged in wholesale merchant functions must abide by FERC's code of conduct rules for market-based rates that govern the relationship between affiliated power marketers and the utilities that have captive ratepayers. The code of conduct rules prohibit the sharing of any wholesale market information by the public utility with captive ratepayers with any employees of the affiliated marketers unless that information simultaneously is made available to non-affiliated competitors. The purpose of the code of conduct is to prevent the transfer of benefits from the utility's ratepayers to stockholders

In compliance with FERC's requirements, APS initially was prohibited from transactions with marketing affiliates and had a Standard FERC Code of Conduct that restricted its relationship with its affiliate APSES. With the anticipated transfer of APS generation to PWEC and the establishment of a marketing and trading arm at Pinnacle West, however, there would be

[40] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (February 25, 2000), FERC Stats. & Regs ¶ 31,092 (2000), *petitions for review dismissed, Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

a need for the Pinnacle West companies to be able to transact business with each other. Therefore, on April 21, 2000, as part of the corporate restructuring envisioned by the 1999 Settlement, Pinnacle West filed with FERC on behalf of itself and its affiliates APS and APSES, an application under section 205 of the Federal Power Act, seeking, among other things: (1) authority for Pinnacle West to engage in wholesale sales of electric power at market-based rates, including market-based rate sales to its affiliates, including APS; (2) approval of revised market-based rate tariffs for APS and APSES to allow them to transact business with affiliates at market-based rates; and (3) approval of a code of conduct for PWCC and proposed modifications to the codes of conduct of APS and APSES that eliminated the provision requiring simultaneous disclosure to the public of all market information shared between APS and its marketing affiliates.[41]

With regard to APS' retail customers, the filing noted that a substantial portion of APS' retail customers were already authorized to choose their generation provider and that those customers not already authorized to make this choice would be eligible on January 1, 2001. In 2001, full retail choice became available and remains available to all retail customers in Arizona. Although all of APS' retail customers currently have choice, few customers have chosen to purchase their power supplies from alternative suppliers under current market conditions, choosing instead to remain with APS. However, it is the ability of retail customers to choose an alternate supplier and not whether they actually do so that is the basis for finding that such customers are protected from potential affiliate abuse

As to APS' captive wholesale customers, the companies proposed in their 2000 filing to protect these customers from potential affiliate abuse by capping APS' system incremental costs ("SIC") component at prices set by a competitive regional market hub (i.e., the Palo Verde Index) for customers with pricing provisions based on the SIC. Specifically, with regard to APS' wholesale power contracts that include a pricing provision based upon APS' system incremental costs, the companies mitigated any concerns regarding potential harm by capping the portions of these customers rates that include an SIC component at the lesser of: (i) the monthly rates calculated utilizing APS' actual hourly SIC values (the existing methodology); (ii) or the monthly rates calculated utilizing a regional market index in lieu of the actual SIC. APS' wholesale SIC contracts referenced in the filing terminated in 2001. Although APS still has a coordination tariff on file at FERC that has SIC provisions, no customers currently take service under that tariff. The companies also proposed similar protections for wholesale customers affected by a fuel adjustment clause.

In an order issued June 20, 2000 on this filing, FERC determined that APS' captive customers were adequately protected from affiliate abuse.[42] APS' retail customers were protected from potential affiliate abuse due to retail customers' ability to choose a supplier and by the rate reductions and limitations in effect. As for APS' captive wholesale customers, FERC determined that APS' captive customers were adequately protected from affiliate abuse by Pinnacle West's

[41] A similar filing was made subsequently on behalf of PWEC. *Pinnacle West Energy Corp.*, 92 FERC ¶ 61,248 (2000), *reh'g denied,* 95 FERC ¶ 61,301 (2001).

[42] *Pinnacle West Capital Corp.*, 91 FERC ¶ 61,290 (2000) ("June 20 Order"), *reh'g denied*, 95 FERC ¶ 61,300 (2001).

proposed safeguards for APS' customers with contracts using a SIC component and fuel adjustment clause.[43]

FERC Standards of Conduct

In Order No. 889,[44] issued concurrent with Order No. 888, FERC also imposed standards of conduct governing communications between the utility's transmission and wholesale power functions, to prevent a utility from giving its power marketing arm preferential access to transmission information. Under Order No. 889, all public utilities that own, control or operate facilities used in the transmission of electric energy in interstate commerce were required to create or participate in an OASIS that provides all existing and potential transmission customers the same access to transmission information to enable them to obtain open access non-discriminatory transmission service. The standards of conduct ensure that the public utility does not use its unique access to information unfairly to favor its own merchant functions, or those of its affiliates, in selling electric energy in interstate commerce. Accordingly, FERC requires that the public utility's employees engaged in transmission system operations must function independently from the public utility's employees and the employees of the affiliates who engage in wholesale merchant functions. Under the functional unbundling requirements, wholesale merchant function employees may not engage in transmission system operation or reliability functions.

In Order No. 889, FERC identified the original objectives of the Standards of Conduct to be: (1) to prohibit preferential access to information regarding transmission prices and availability to employees of wholesale merchant functions; (2) to ensure that employees in systems operations and reliability functions treat all customers fairly and impartially without preferential treatment of employees in wholesale merchant functions; and (3) to provide functional unbundling of transmission operations and wholesale merchant functions to allow impartial operation benefiting all. However, to avoid any compromise on reliability, FERC provided exemptions for emergencies. APS and its affiliates are in full compliance with the requirements of Order No. 889.

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[43] *Pinnacle West Capital Corp.*, 91 FERC ¶ 61,290 (2000), *reh'g denied*, 95 FERC ¶ 61,300 (2001); *see also Pinnacle West Energy Corp.*, 92 FERC ¶ 61,248 (2000), *reh'g denied*, 95 FERC ¶ 61,301 (2001). On December 30, 2002, GenWest, LLC, a subsidiary of PWEC that owns a generating facility outside of Las Vegas, Nevada, filed an application for market-based rates and for the same code of conduct waivers applicable to Pinnacle West, APS, PWEC and APSES. FERC staff requested GenWest to address whether the earlier code of conduct waivers were still warranted, and on April 10, 2003, GenWest filed an amended application addressing those issues. In a letter order issued June 6, 2003, in Docket No. ER03-352, FERC accepted for filing GenWest's market-based rates and the requested modified code of conduct.

[44] Open Access Same-Time Information System and Standards of Conduct, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996); *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997); *order on reh'g*, Order No. 889-B, FERC Stats. & Regs. ¶ 31,253 (1997); *order on reh'g*, Order No. 889-C, 82 FERC ¶ 61,046 (1998).

FERC Supply Margin Assessment ("SMA") Test

Traditionally, FERC allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry. FERC also considers whether there is a basis for concern that the grant of market rate authority will result in a reduced ability for regulators to monitor affiliate dealings to assure that there is no abuse. FERC has granted market-based rate authority to APS, Pinnacle West, PWEC and APSES based on such determinations.

In the SMA Order,[45] FERC outlined a new methodology to be used by applicants requesting market-based rate authority under Section 205 of the Federal Power Act. FERC also noted in the SMA Order that the SMA test is an interim method to be used until FERC adopts a new long-term methodology.

In non-ISO/RTO markets, the SMA test identifies whether the applicant is a pivotal supplier needed to meet peak load in the control area. Specifically, applicants are instructed to compare the applicant's generation capacity in the market to the difference between "Available Supply" and peak demand in the market (termed the "Supply Margin"). Available Supply includes all of the generating capacity located in the market, plus uncommitted capacity that can reach the market using available inbound transmission capacity, as measured by the Total Transfer Capability ("TTC") value. This capacity is then compared to peak load in the control area. If peak load can be met without the applicant's or its affiliates' capacity, then the applicant is not a pivotal supplier and the SMA test is passed. In markets where the applicant does not pass the SMA screen, FERC may condition or deny market-based rate authority.

Pinnacle West and its affiliates completed and recently submitted to FERC an analysis of the SMA test as applied to the control areas in which they own generation (APS, SRP and, in 2004, the Nevada Power control areas).[46] As described more fully below, the SMA test is easily passed in all markets. The results of the study showed there are no generation market power or other competitive concerns regarding continuing Pinnacle West's or its affiliate's market-based rate authority.

In the APS control area, both PWEC and APS own generating facilities physically located inside and outside of the APS control area. For purposes of the SMA test, all of the generation owned by these companies in the APS control area was included. The results show

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[45] *AEP Power Marketing, Inc., AEP Service Corporation, CSW Power Marketing, Inc., and Central and South West Services, Inc.; Entergy Services, Inc.; Southern Company Energy Marketing L.P.*, Order on Triennial Market Power Updates and Announcing New, Interim Generation Market Power Screen and Mitigation Policy, 97 FERC 61,219 (2001) ("SMA Order").

[46] Triennial SMA filing in FERC Docket Nos. ER99-4124-001, ER00-2268-003, ER00-3312-002 and ER99-4122,004, submitted April 10, 2003. A similar SMA screen was submitted earlier by GenWest, LLC, a PWEC subsidiary, for its Silverhawk facility, which is located outside of Las Vegas. That filing was made in connection with GenWest's application to sell at market rates. *See* FERC Docket No. ER03-352-000. As noted, GenWest's application for market-based rates, based on the SMA analysis of all of the Pinnacle West companies, was accepted on June 6, 2003.

that the amount of generation owned by these companies is much less than the Supply Margin for the APS control area, and therefore the SMA test is easily passed.

In the Salt River Project control area, both APS and PWEC own capacity. Once again, the analysis shows that the Supply Margin is greater than the capacity of APS and PWEC and the SMA test is passed. That is, APS and PWEC are not pivotal suppliers under the SMA test.

In the Nevada Power control area, the analysis was performed using a conservative estimate of the total capacity expected to be on-line during the summer 2004. As noted above, the SMA test also includes uncommitted generation outside of the control area, limited to the minimum of either the uncommitted generation or the TTC into the market. The Supply Margin is the difference between Available Supply and peak load. Because PWEC's capacity in this market consists only of only one facility (Silverhawk, owned by PWEC's subsidiary GenWest, LLC), the results of the analysis show that the Supply Margin is greater than the capacity of PWEC and the SMA test is passed.

Although the SMA test is intended to address generation market power, FERC also has expressed concern that an applicant might have transmission market power or be able to erect barriers to entry of new generation as a result of control over sites and fuels delivery systems. FERC typically has accepted an approved open access transmission tariff as demonstrating the requisite absence or mitigation of transmission market power. As additional support for its SMA filing, Pinnacle West and its affiliates provided information showing that they lack transmission market power as well. For example, APS, which owns transmission assets, has an open access transmission tariff on file with FERC. Further, APS is one of the filing utilities in support of the WestConnect RTO. Pinnacle West and its affiliates also provided information regarding substantial new entry in the relevant markets and surrounding control areas.

2. *Corporate Governance Requirements*

In evaluating compliance, the Commission must also consider the obligations of Pinnacle West and its subsidiaries, including APS, and their directors, officers, and employees to operate according to corporate governance standards established by state and federal law. Recently adopted statutory and regulatory requirements, most importantly the Sarbanes-Oxley Act of 2002 ("Sarbanes-Oxley"), have re-emphasized the significance of corporate governance and impose stringent requirements on "public" companies (*i.e.*, companies that are required to file periodic reports and financial information with the SEC), such as Pinnacle West and APS, as well as their directors, officers, and employees. These requirements are in addition to those imposed by Arizona law. A common theme lies at the heart of each of these corporate governance requirements—every corporation must establish appropriate processes to effectively collect and publicly disclose material information to the corporation's investors or potential investors. Failure to do so can result in significant civil and criminal penalties.

Sarbanes-Oxley Requirements

Sarbanes-Oxley, enacted as a response to the failure of certain corporate executives to effectively police company activities, requires corporate executives to be fully informed about the financial and operational condition of their corporations. The following summarizes several requirements of Sarbanes-Oxley.[47]

Certification of Financial Statements and Disclosure Controls and Procedures. Section 906 of Sarbanes-Oxley requires the CEO and CFO of APS and Pinnacle West to certify in every SEC periodic report containing financial statements that the filing fully complies with SEC requirements and that the information contained in the filing fairly presents, in all material respects, the financial results and operations of APS and Pinnacle West, respectively. A violation of Section 906 can result in a civil penalty of up to $5,000,000 and a prison term of up to 20 years. The CEO and the CFO depend on a free flow of information from APS, Pinnacle West, APSES, and Pinnacle West Energy to ensure the required levels of public disclosure necessary for the CEO and CFO to make the certifications.

Section 302 of Sarbanes-Oxley further requires the CEO and CFO of APS and Pinnacle West to certify in quarterly and annual SEC filings that (a) they have reviewed the filing; (b) to their knowledge, the filing does not contain any untrue statement or omission of material fact; (c) to their knowledge, the financial statements fairly present the company's financial condition and results; and (d) they have established and maintain appropriate "disclosure controls and procedures" (defined below) to ensure that material information relating to each company has been gathered and publicly disclosed. The CEO and CFO of APS and Pinnacle West must also include a separate report in each quarterly and annual SEC filing detailing their conclusions

[47] Sarbanes-Oxley imposes numerous additional responsibilities on public companies and their directors, officers, and employees. Since the July 30, 2002 effective date of Sarbanes-Oxley, Pinnacle West has completed numerous corporate governance initiatives, many well in advance of the compliance deadlines. These corporate governance initiatives, many of which formalized existing practices, include (a) the successful completion of the SEC's full review of Pinnacle West/APS SEC filings; (b) the adoption of Director Independence Standards; (c) formalization of periodic meetings of non-management directors; (d) the designation of a "Presiding Director" through whom interested parties may communicate with the non-management directors; (e) the establishment of a Corporate Governance Committee composed entirely of independent directors; (f) the adoption of a new Human Resources Committee Charter giving the committee additional authority and responsibility, consistent with New York Stock Exchange rule proposals; (g) the adoption of Corporate Governance Guidelines; (h) the determination of an "audit committee financial expert"; (i) the approval of a new Audit Committee Charter giving the committee additional authority and responsibility, consistent with Sarbanes-Oxley and New York Stock Exchange rule proposals; (j) implementation of Sarbanes-Oxley requirements that the Audit Committee retain and approve the compensation of the outside auditor and pre-approve the outside auditor's services; (k) implementation of a two-day "Section 16" insider trading reporting process, consistent with Sarbanes-Oxley; (l) early voluntary disclosure of off-balance sheet transactions in SEC filings; (m) early voluntary disclosure of "critical accounting policies" in SEC filings; (n) early voluntary compliance with new SEC rules regarding disclosure of pro forma financial information; and (o) expanded website disclosure (www.pinnaclewest.com), including (i) Section 16 Reports, (ii) SEC filings (i.e., Form 10-Qs, Form 10-Ks, and Form 8-Ks), (iii) charters of Audit Committee, Human Resources Committee, Corporate Governance Committee, and Operating and Finance Committee, and (iv) Pinnacle West's Corporate Governance Guidelines. Many of these corporate governance initiatives are discussed in detail in Pinnacle West's 2003 proxy statement, which is also available on its website. Based on a variety of corporate governance factors, as of June 11, 2003, Institutional Shareholder Services ("ISS") has assigned Pinnacle West a "Corporate Governance Quotient" that places Pinnacle West in the top quarter of all companies in the ISS utilities group.

about the effectiveness of each corporation's disclosure controls and procedures, which are defined as follows:

> [T]he term "disclosure controls and procedures" means controls and other procedures of an issuer that are designed to ensure that information required to be disclosed by the issuer in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Commission's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Exchange Act is accumulated and communicated to the issuer's management, including its principal executive officer or officers and principal financial officer or officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.[48]

Code of Ethics. Section 406 of Sarbanes-Oxley requires APS and Pinnacle West to disclose whether they have a Code of Ethics applicable to the CEO, CFO, and principal accounting officer. Item 406 of SEC Regulation S-K, which implements Section 406 of Sarbanes-Oxley, requires that a qualifying Code of Ethics must be reasonably designed to deter wrongdoing and to promote:

- honest and ethical conduct, including the ethical handling of actual or apparent conflicts of interest between personal and professional relationships;
- full, fair, accurate, timely and understandable disclosure in reports and documents that comply with SEC requirements;
- compliance with applicable governmental laws, rules and regulations;
- prompt internal reporting to an appropriate person identified in the code of violations of the code; and
- accountability of adherence to the code.[49]

Section 406 not only governs the conduct of the executives, but, as mentioned with respect to Sections 302 and 906 above, it requires adequate information so that the CEO, CFO, and others can ensure proper SEC disclosures. Section 406 references the necessity of prompt

[48] Rule 13a-14(c), Securities Exchange Act of 1934, as amended (the "Exchange Act") (emphasis added). Like many other public companies, APS and Pinnacle West have established a "Disclosure Review Committee" to promote effective disclosure controls and procedures. The Disclosure Review Committee consists of executive officers, accountants, auditors, and internal and external legal counsel and provides reports to the Audit Committee regarding, among other things, APS' and Pinnacle West's disclosure controls and procedures.

[49] Item 406(b) of Regulation S-K.

internal reporting of code violations, which further underscores the critical role of "disclosure controls and procedures." APS and Pinnacle West have implemented a Code of Ethics.[50]

Reporting of "Material Violations." Section 307 of Sarbanes-Oxley is an example of another legal requirement that mandates communications essential for effective corporate governance. Section 307 requires attorneys "practicing before the SEC" (for example, attorneys preparing APS' and Pinnacle West's SEC filings) who become aware of (a) evidence of a material violation of federal or state securities laws; (b) a breach of a fiduciary duty; or (c) a violation of similar laws, to report such breaches or violations to the company's Chief Legal Officer (or the CEO, if there is no Chief Legal Officer), the board of directors, or a special board committee. This reporting obligation of the attorney is often called "up the ladder" reporting because the attorney has an obligation to report the breach or violation up the ladder until the issue is responded to or resolved.

Arizona Law

Arizona law also imposes additional corporate governance requirements on APS' and Pinnacle West's officers and directors.[51] APS' and Pinnacle West's officers have a statutory

50 The Ethics Policy and Standards of Business Practice (the "Code of Ethics") of Pinnacle West and its subsidiaries are detailed in a document entitled "Doing The Right Thing." The Code of Ethics covers all Pinnacle West, APS, PWEC and APSES employees, including each CEO, CFO, and principal accounting officer. The Code of Ethics, when combined with the disclosure controls and procedures discussed above, complies in all respects with Item 406(b) of Regulation S-K. Each employee is required to report Code of Ethics violations or suspected violations to the employee's immediate leader or to a hotline. The New York Stock Exchange has also proposed rule amendments that would require listed companies, like Pinnacle West, to have a Code of Business Conduct and Ethics for directors, officers, and employees, which must include the reporting of any illegal or unethical behavior (Proposed Listing Standard, Item 303A.10). The New York Stock Exchange has also proposed a requirement that New York Stock Exchange-listed companies, like Pinnacle West, must have corporate governance guidelines giving directors direct access to management (Proposed Listing Standard, Item 303A.9).

51 Pinnacle West has established a corporate governance framework that assists the officers and directors of Pinnacle West and its subsidiaries in fulfilling their statutory obligations, as described in this section. Many aspects of this framework are described in footnote 47 above. With respect to officers, the standing committees of Pinnacle West's board of directors (described more fully in footnote 47), provide guidance to, and assess the performance of, officers and employees. The Human Resources Committee is responsible for identifying qualified individuals to serve as officers and reviewing the officers' performance. Similarly, the Audit Committee is responsible for the oversight of Pinnacle West's internal audit function and management's relationship with the independent auditor. The officers of Pinnacle West and its subsidiaries participate in quarterly leadership meetings, which include 200-250 leaders from throughout the organization. In addition to the operational issues addressed at these meetings, topics have included leadership principles; corporate values, including those embodied in the Code of Ethics; diversity; and legal developments. These quarterly leadership meetings are in addition to the quarterly meetings attended by all officers, the frequent officer staff meetings at which these and other issues are discussed, and the ongoing communication among officers regarding issues relating to the effective performance of their responsibilities. Pinnacle West also makes available to its management team, including its officers, formal leadership training provided by third parties, such as Arizona State University.

obligation to discharge their duties (a) in good faith; (b) with the care an ordinary prudent person in a like position would exercise under similar circumstances; and (c) in a manner the officers reasonably believe to be in the best interest of the corporation (A.R.S. § 10-842(A)). In discharging his or her duties, an officer is entitled to rely on information, opinions, reports, or statements, including financial statements and other financial data, if prepared or presented by (i) one or more directors, officers or employees of the corporation whom the officer reasonably believes are reliable and competent in the matters presented; or (ii) legal counsel, public accountants, or other persons as to matters the officer reasonably believes are within the person's professional or expert competence (A.R.S. § 10-842(B)). As is the case with the Sarbanes-Oxley provisions discussed above, APS' and Pinnacle West's officers depend on communication from employees to fulfill these Arizona statutory obligations.

The legal obligations of directors fall into two broad categories: a duty of care and a duty of loyalty. The duty of care requires a director to act in good faith and on the basis of adequate information in arriving at business decisions. This duty of care is codified in the Arizona statutes, which place a statutory obligation on APS' and Pinnacle West's directors to manage the business and affairs of Pinnacle West (A.R.S. § 10-801) and to discharge their duties (a) in good faith; (b) with the care an ordinary prudent person in a like position would exercise under similar circumstances; and (c) in a manner the directors reasonably believe to be in the best interests of the corporation. (A.R.S. § 10-830(A)). Similar to officers, in discharging their duties directors are entitled to rely on information, opinions, reports, or statements, including financial statements and other financial data, if prepared or presented by (i) one or more officers or employees of the corporation whom the director reasonably believes are reliable and competent in the matters presented; (ii) legal counsel, public accountants, or other persons as to matters the director reasonably believes are within the person's professional or expert competence; or (iii) a committee of the board of which the director is not a member if the director reasonably believes the committee merits confidence (A.R.S. § 10-830(B)).

An important corollary to the statutory standard of conduct of directors set forth in A.R.S. § 10-830 (A) and (B) is the business judgment rule. The presumptions afforded by the business judgment rule are expressly recognized and preserved in the statute, which provides that a director is presumed in all cases to have acted, failed to act, or otherwise discharged such director's duties in accordance with the statute (A.R.S. § 10-830(D)). Although there is no relevant Arizona case law directly citing to any of the officer or director statutes mentioned

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With respect to directors, each standing board committee operates under a detailed charter designed to ensure that each committee member is qualified, informed and prepared to perform in accordance with the responsibilities specified the committee charter. The recently established Corporate Governance Committee not only identifies and evaluates qualified individuals to serve as directors, it is also responsible for developing corporate governance principles (set forth in Pinnacle West's Corporate Governance Guidelines) to establish director qualification standards, director responsibilities, director self-evaluation procedures, and policies and principles for CEO selection and performance review. These Corporate Governance Guidelines, which are posted on Pinnacle West's website, further require the board of directors to oversee Pinnacle West's compliance with its Code of Ethics, allow all directors full and free access to management, and make continuing education available to directors. Pinnacle West's board of directors is also frequently updated on current state and federal legal developments affecting their responsibilities.

herein, Arizona courts have provided interpretation of the duties associated with the business judgment rule.

APS' and Pinnacle West's directors are required to reasonably inform themselves in order to gain the protections offered to them by the business judgment rule. In *Resolution Trust Corp. v. Blasdell*,[52] the court stated that "the business judgment rule, stated generally, 'precludes judicial inquiry into actions taken by a director in good faith and in the exercise of honest judgment in the legitimate and lawful furtherance of corporate purpose.'" The court further described the business judgment rule by stating, "[t]he rule thus applies if directors act in furtherance of a legitimate corporate purpose, in good faith, and *after reasonably informing themselves*."[53] Further addressing this concept, the Arizona Court of Appeals stated that in order to "invoke the rule's protection directors have a *duty to inform themselves*, prior to making a business decision, *of all material information reasonably available to them*. Having been so informed, they must then act with the requisite care in the discharge of their duties."[54] The duty imposed on directors to reasonably inform themselves requires APS' and Pinnacle West's directors to maintain open lines of communication with employees, officers, and others within Pinnacle West and its subsidiaries.

The duty of loyalty also governs the conduct of APS' and Pinnacle West's directors. This duty of undivided and unqualified loyalty to the corporation for which they serve prohibits directors from (i) using their positions to profit personally at the expense of the corporation; (ii) usurping, for their own advantage, an opportunity that rightly belongs to the corporation; and (iii) entering into unfair transactions or contracts with the corporation. In *Phoenix Title and Trust Co. v. Alamos Land and Irrigation Co.*,[55] the Arizona Supreme Court stated that directors "must not in any degree...allow their official conduct to be swayed by their private interest, unless that interest is the interest which they have in the good of the company in common with all the other shareholders. This principle is asserted and illustrated by judicial decisions almost without number. This duty results from the nature of their employment, and without any stipulation to that effect. Their private interest must yield to their official duty whenever those interests are conflicting. They must neither exercise their trust for their own private exclusive benefit, nor for the benefit of third persons."[56] Any possible conflicts or potential breaches of this duty of loyalty must be communicated to officers, directors and others in order to resolve the conflict and protect the interests of the investors.

In today's business environment, corporate governance and the state and federal laws that apply to the conduct of the officers and directors of corporations are increasingly important. APS and its affiliates have been aggressive in implementing not just the letter but also the spirit embodied in Sarbanes-Oxley and other corporate governance laws. The directors and officers are

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52 930 F. Supp. 417, 423 (D. Ariz. 1994).

53 *Id.* at 424 (emphasis added).

54 *Blumenthal v. Teets*, 155 Ariz. 123, 128 (Ariz. Ct. App. 1987) (emphasis added).

55 24 Ariz. 499, 507 (Ariz. 1922).

56 *Id.*

acutely aware of both their duties of loyalty and of the need to be informed of the business conduct of their company. The proactive actions undertaken by APS and its affiliates to meet all applicable corporate governance responsibilities have been both prudent and effective.

3. Antitrust Laws

The electric industry is subject to numerous federal and state antitrust laws affecting both the structure and behavior of industry companies. Specifically, several antitrust laws apply broadly to electric utilities in Arizona, although some are obviously limited under circumstances where the state has adopted a policy of regulated monopoly, such as for utility distribution service. These include:

- Section 1 of the Sherman Act, 15 U.S.C. § 1, which prohibits those contracts, combinations and conspiracies that unreasonably restrain trade;
- Section 2 of the Sherman Act, 15 U.S.C. § 2, which proscribes monopolization and attempts to monopolize;
- the Arizona Uniform Antitrust Act, A.R.S. §§ 44-1401, *et seq.*, which substantially follows the proscriptions of the Sherman Act; and
- the Federal Trade Commission Act, 15 U.S.C. § 45(a), which applies to unfair and deceptive acts and practices as well as providing authority to the Federal Trade Commission ("FTC") also to enforce the federal antitrust laws, other than the criminal provisions, which are enforced solely by the U.S. Department of Justice Antitrust Division.

The Sherman Act has long been applied to the electric industry, with respect both to challenges concerning agreements among electric utilities,[57] and concerning monopolization issues, such as access to transmission lines,[58] and alleged anticompetitive attempts to leverage a utility's position in one market into a second, unregulated, market.[59] Additionally, the Clayton Act and Robinson-Patman Act have been held to apply to the electric industry.[60]

It is important to recognize that the antitrust laws are intended to protect the competitive process. As the United States Supreme Court repeatedly has observed, the purpose of the antitrust laws is "to protect competition, not competitors."[61] Antitrust analysis thus focuses on

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[57] *See, e.g., United States v. Rochester Gas & Electric Co.*, 4 F. Supp 2d 172 (W.D.N.Y. 1998); *Gainesville Utilities Dep't v. Florida Power & Light Co.*, 573 F.2d 292 (5th Cir. 1978).

[58] *See, e.g., Otter Tail Power Co. v. United States*, 410 U.S. 366 (1973); *City of Chanute v. Kansas Gas & Electric Co.*, 754 F.2d 310 (10th Cir. 1985).

[59] *See, e.g., Yeager's Fuel, Inc. v. Pennsylvania Power & Light Co.*, 953 F. Supp. 617 (E.D. Pa. 1997).

[60] *See, e.g., City of Kirkwood v. Union Electric Co.*, 671 F.2d 1173 (8th Cir. 1982), *cert. denied*, 459 U.S. 1170 (1983) (applying Robinson-Patman Act).

[61] *Brunswick Corp. v. Pueblo Bowl-O-Mat, Inc.*, 429 U.S. 477, 488 (1977).

whether a particular corporate structure or practice enhances economic efficiency, and thereby enhances consumer welfare.

Consequently, the antitrust laws do not condemn vertical integration, or business dealings among corporate affiliates of vertically-integrated companies, such as electric utilities. On the contrary, such vertical integration is considered, from an antitrust perspective, as efficiency-enhancing and thus contributing to consumer welfare, through reduction of production and transaction costs. As the leading antitrust law treatise concludes:

> Vertical integration can produce significant cost reductions by enabling the integrating firm to achieve two kinds of efficiencies. "Production" efficiencies . . . and "transactional" efficiencies . . . .
>
> In speaking of the evils of vertical integration, courts sometimes identify the harm as "unfair" advantage" over unintegrated rivals. But in most cases the only advantage at issue is the integrating firm's ability to reduce its cost below that of unintegrated firms.[62]

To protect these efficiencies, which further the purpose of the antitrust laws to enhance consumer welfare, courts have rejected antitrust challenges to vertically-integrated firms' coordination of activities among their affiliates, even where the result is to injure a rival firm.[63]

Thus, *no* coordination between APS, Pinnacle West and PWEC regarding electric industry restructuring in Arizona would violate any applicable antitrust law. For example, PWEC presenting a business assumption regarding the anticipated transfer of APS generation to acquire a contingent investment grade credit rating would not violate any antitrust law. To impose restrictions on communications or coordination of activities among an electric utility's affiliates would simply sacrifice efficiencies, raise the costs of the incumbent utilities, and subsidize other less efficient firms, all to the detriment of consumers and the competitive process.[64] None of APS' actions nor those of its affiliates have violated any applicable antitrust laws and no party has accused APS or an affiliate of such a violation. Further, antitrust issues based on monopolization or attempt to monopolize are of no concern in this instance, because APS and its affiliates all pass FERC's Supply Margin Assessment screen regarding potential market power held by electric utilities.

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[62] IIIA P. AREEDA & H. HOVENKAMP, ANTITRUST LAW ¶ 757a at 23 (2d ed. 2002).

[63] *See, e.g., Berkey Photo v. Eastman Kodak Co.*, 603 F.2d 263 (2d Cir. 1979), *cert. denied*, 444 U.S. 1093 (1980); *Grason Electric Co. v. Sacramento Municipal Utility District*, 571 F. Supp. 1504, 1528-29 (E.D. Cal. 1983).

[64] For a detailed discussion of the legal and economic concerns regarding imposition of such restrictions, *see* C.O. Hobbs, S.P. Mahinka and T.A. Gebhard, *State Marketing Restrictions on Electric Utilities: Analysis of the Adverse Effects on Competition from Competitive Handicapping* (Edison Electric Institute Monograph, Sept. 1997).

V. Responses to Specific Assertions

A. Formation of PWEC and Construction of Units

During the hearing on the APS Financing Application, various parties questioned the formation of PWEC and its reasons for constructing new generation in Arizona. Those questions appeared to give rise to some concern on the part of the Chief Administrative Law Judge and the Commission. Yet, when the actions of APS and PWEC are reviewed in light of the history of the energy market in Arizona and the West, as discussed above, it becomes clear that both APS and PWEC acted consistent with Commission guidance and requirements, and took appropriate steps to protect APS' customers. By dedicating its capacity to APS customers, PWEC prevented APS from falling victim to the rush into high-priced, long-term contracts that occurred in California, Nevada and other states in the Western United States. In no small measure, it was PWEC's and Pinnacle West's actions that allowed APS to weather the Western power crisis.

Rule 1615 as finally enacted required the divestiture of all APS generation assets (as well as other competitive services) to an unaffiliated party or a separate corporate affiliate prior to January 1, 2001.[65] In the 1999 Settlement and Decision No. 61973 approving the 1999 Settlement, the Commission approved the transfer of APS' generating assets to a separate affiliate of APS (PWEC) but extended the transfer date to the end of 2002. In the decision approving the Settlement, the Commission specifically concluded that it "*supports and authorizes* the transfer by APS *to an affiliate* or affiliates *all* of its generation..."[66] Further, in the Settlement the Commission also agreed that allowing APS' generation to be owned by an affiliate would (1) "benefit consumers," (2) was "in the public interest," and (3) "does not violate Arizona law." And, the Commission also acknowledged that APS would purchase energy from that affiliate, and such purchases (1) "will benefit consumers and...not violate Arizona law," (2) would not provide APS' affiliate with "an unfair competitive advantage by virtue of its affiliation with APS," and (3) that such transactions were "in the public interest."[67]

PWEC was formed to implement the Commission's generation divestiture requirement. In approving the 1999 Settlement, the Commission stated that it "supported" the transfer of all of APS' generation to a Pinnacle West subsidiary, and that sales to APS by that subsidiary at market-based rates were in the public interest, would not violate Arizona law, would not give the affiliate an undue competitive advantage, and would benefit customers.

Thus, in response to the Commission's requirements, PWEC was created for the purpose of and with the expectation that it would receive and own all of APS' generation assets. Under both the Electric Competition Rules and APS' Code of Conduct, APS was not permitted to

65 A.A.C. R14-2-1615(A).

66 Decision No. 61973 at 10 (emphasis added).

67 *Id.*, Attachment 1 at 6-7.

construct new generation.[68] Moreover, because only prudent costs associated with transferring APS generation to PWEC were recoverable, there would certainly have been a challenge to the recovery of transfer costs associated with new generation when APS knew that it was required to transfer all of its generation to PWEC by the end of 2002. Thus, in addition, PWEC was intended to help ensure that APS and APS customers had access to necessary generation resources.

After its formation, and in response to APS' rapidly growing customer demand, PWEC set out to construct or purchase generation in locations designed to ensure that APS' energy needs would be met. By the late 1990s, there was significant growth in demand for power both in the region and specifically among APS customers. Growth in the Valley was especially pronounced. APS' analyses were showing that APS would reach a generation deficit of 2200 MW by 2007 and that other utilities in the Southwest were increasingly short of generating capacity. Also, in 1998 and 1999, the surge in merchant generation construction in Arizona had yet to occur.

Because APS' Code of Conduct and the Electric Competition Rules prohibited APS from constructing new generation after the 1999 Settlement, PWEC constructed both temporary and long-term capacity to benefit APS customers. In large part, this new capacity spared APS from entering into high-priced long-term contracts like other Western utilities during the 2000-2001 energy crisis.

The plans for PWEC's construction of both Redhawk and West Phoenix 4 and 5 were publicly announced and well-known to the Commission. In fact, APS identified Redhawk and expansions at Saguaro and West Phoenix as necessary and planned resources to the Commission during a summer preparedness hearing in early 2001.[69] No merchant generator nor any other party raised any objections to those goals as stated at the time they were announced. PWEC commenced its construction program in response to the then existing and anticipated dramatic capacity shortages being experienced in the state and the Western United States.[70]

[68] Specifically, Section X(B) of APS' Code of Conduct prohibits APS from engaging in "Interim Competitive Activities," which is defined as "Competitive Services, exclusive of those set forth in Rule 1615(B), that APS may lawfully provide until December 31, 2002." In the Financing Application, certain parties contended that constructing new generation was not a "Competitive Service" because it would serve non-competitive Standard Offer customers. That assertion is refuted by the Concise Explanatory Statement that accompanied the final Electric Competition Rules, which explained that it is "clear that competitive generation includes all generation except for Must-Run Generating Units." The 1999 Settlement also required the divestiture of *all* generating units. Having fought over the divestiture requirements for two years, it would have been unreasonable and futile for APS to have sought authorization to construct the PWEC generation just months after both the 1999 Settlement and the final Electric Competition Rules were approved by the Commission.

[69] APS Presentation at Commission's Energy Workshop, February 16, 2001.

[70] Additional detail regarding both the development and construction of the PWEC generation units will be provided in the rate case filing that APS will submit to the Commission.

Although California experienced rolling blackouts and both California and Nevada entered into long-term contracts that they are now attempting to terminate, APS was able to weather the storm due in large part to the efforts undertaken by PWEC. Instead of forcing APS to look to the unstable wholesale market, PWEC undertook a multi-pronged approach to assist APS in meeting its energy needs. First, PWEC specifically looked for opportunities to construct new generation within APS' well-known Metro Phoenix load pocket and subsequently announced the construction of West Phoenix CC4 and CC5. Moreover, when it became apparent that Arizona could experience during the summer of 2001 the shortages already being experienced in California and Nevada, PWEC accelerated the completion of West Phoenix CC4 and located 198 MW of temporary, trailer-mounted generation at the West Phoenix and Saguaro plants to ensure reliability for APS' customers.[71] Finally, to ensure that APS' needs would be met in 2002, PWEC also accelerated the in-service date of Redhawk Units 1 and 2 from 2003/2004 to 2002.[72]

The all-too-recent past in California and Nevada makes reliability a continuing concern of APS and there are significant future challenges already on the horizon. The competitive wholesale market continues to be challenging, exhibiting significant volatility. Little additional generation is planned and more plants are being cancelled or delayed, despite continued load growth throughout the Western United States. And, financing for new power plant construction remains largely unavailable. These facts suggest that, in the future, unexpected increases in demand could be met with insufficient supply. Further, there is continuing uncertainty regarding wholesale market design, credit quality concerns amongst counter-parties, and continuing challenges to wholesale power contracts at FERC and elsewhere. In APS' case, the relatively poor response of merchant generators in the recently-completed Track B competitive solicitation highlights these concerns.

B. PWEC Financing

Decision No. 65796 alleges that "PWEC made presentations to rating agencies indicating that PWEC was under contract to sell its output to APS under a four-year purchase power agreement." That decision also referred to a provision in Decision No. 61973 that APS not "subsidize the spun-off competitive assets through an unfair financial arrangement" and appears to suggest that this provision is implicated somehow in the PWEC financing arrangements.

The financing arrangements for the PWEC units did not violate either the letter or spirit of the Electric Competition Rules, Decision No. 61973, the APS Code of Conduct, or any applicable law. And, there was no misrepresentation made to the ratings agencies regarding any arrangement between APS and PWEC regarding future power sales or regarding the

[71] At the same time, APS re-commissioned two steamer units (4 and 6) at the West Phoenix Power Plant. Without those APS steamer units, PWEC's West Phoenix CC4, and the temporary units brought in by PWEC, APS could have faced serious capacity shortages during the summer of 2001.

[72] PWEC also pursued a variety of partnerships and purchase options in order to obtain capacity to meet Arizona's rapidly growing demands. For example, as explained during the hearing on the Financing Application, PWEC pursued options for joint construction with both Calpine and Reliant. In addition, purchases from Southern California Edison and El Paso Electric of shares in existing units were considered. As it became clear that none of those options would come to fruition, PWEC focused its efforts on constructing generation to meet Arizona's needs.

requirements of the Electric Competition Rules and 1999 Settlement. Rather, these financing activities were a logical and sensible response to the Commission's divestiture requirements in the Electric Competition Rules and the 1999 Settlement and were conducted in a straightforward and professional manner.

First, the decision of how to finance the construction of the PWEC units was based on the circumstances existing at the time the decision was made. In late 1999 and early 2000, everyone expected that APS would be divesting all of its generation assets to PWEC as required by Decision No. 61973 and the APS Settlement. With that assumption, and considering the relatively short three-year time horizon over which that divestiture was supposed to occur, the most economical and least complex and restrictive approach to financing was to issue short-dated parent debt that would come due shortly after the anticipated divestiture was completed. Then, once the assets were transferred, PWEC would be able to take advantage of its investment grade credit ratings, and access the debt capital markets at a lower cost than if it had issued long-term debt without the investment grade ratings. This subsequent debt would be of a longer maturity, reflecting the long-lived nature of the assets being financed.

Additionally, the construction of the PWEC units, including the fact that the units were being constructed in APS' service territory, was very public. The Arizona Power Plant and Transmission Line Siting Committee and the Commission approved Certificates of Environmental Compatibility for the units in 2000. The units were discussed during APS' summer preparedness hearings at the Commission and in conversations with the Governor. And, the decision to issue bridge debt to finance the PWEC assets was disclosed in numerous public filings.[73] Under Arizona law, neither Pinnacle West nor PWEC were required to obtain Commission approval to issue debt or obtain financing to construct the units.[74]

The contingent credit ratings obtained by PWEC, which were investment grade ratings contingent on PWEC actually acquiring the APS generation as promised in the 1999 Settlement, were not inconsistent with the discussion in Decision No. 61973 regarding the financing arrangements of the spun-off APS generation. That decision stated:

> Some parties were concerned that Section 4.1 and 4.2 [of the APS Settlement] provide in effect that the Commission will have approved in advance any

[73] *See, e.g.,* Pinnacle West's 1999 Form 10-K under GENERATION EXPANSION: "Pinnacle West Energy's capital expenditures will be funded with debt proceeds, and internally-generated cash and debt proceeds from the parent company"; Pinnacle West's 2000 Form 10-K under GENERATION EXPANSION: "Pinnacle West Energy's expenditures are expected to be funded through internally-generated cash and debt issued directly by Pinnacle West Energy, as well as capital infusions from Pinnacle West's internally generated cash and debt proceeds"; Pinnacle West's 2001 Form 10-K under GENERATION EXPANSION: "Pinnacle West Energy is currently funding its capital requirements through capital infusions from Pinnacle West, which finances those infusions through debt financings and internally-generated cash."

[74] A.R.S. § 40-301 and A.R.S. § 40-302 both apply only APS and APSES. Because the financing of the PWEC assets did not involve APS, neither A.A.C. R14-2-804 nor any of the other Affiliated Interest Rules nor the APS Code of Conduct were implicated by these actions.

> proposed financing arrangements associated with future transfers of "competitive services" assets to an affiliate....We share the concerns that the non-competitive portion of APS not subsidize the spun-off competitive assets through an unfair financial arrangement. We want to make it clear that the Commission will closely scrutinize the capital structure of APS at its 2004 rate case and make any necessary adjustments.[75]

The potential concern addressed in Decision No. 61973 and the financing arrangements made by PWEC are completely different and wholly unrelated issues. In the hearings and during the briefing of the APS Settlement, some parties had expressed concerns that the transfer of the APS generation, which would require some division of debt and equity within APS as the APS generation is both debt and equity financed, could affect the capital structure of APS in a manner detrimental to customers.[76] For example, Enron noted in its post-hearing brief that debt financing was less expensive than equity financing and is tax deductible. Thus, Enron's concern was that the APS generation could be transferred using a highly-leveraged structure, which would lower the cost of capital to PWEC and "shift the higher cost of capital (equity) to the regulated company."[77] Thus, the decision contained the language regarding the scrutiny that would be given in the 2004 rate case to ensure that such subsidization fom the capital structure of any transfer did not occur.

The financing arrangements made by PWEC do not raise this concern for several reasons. First, APS could not "subsidize" the financing of the PWEC units because APS was not financing them at all. The debt and equity associated with the PWEC units was held at Pinnacle West and was intended to be held at PWEC post-divestiture. Second, seeking a contingent investment-grade credit rating based on a business assumption that the 1999 Settlement actually would be implemented is hardly subsidization. The Commission had already ordered APS to divest *all* of its generation to PWEC. For PWEC to plan its business model on this assumption is both rational and to have been expected. And, the Commission in the Settlement had expressly agreed that PWEC "will be subject to regulation by the Commission, to the extent otherwise permitted by law, to no greater manner or extent than the manner and extent of Commission regulation imposed upon other owners or operators of generating facilities."[78] No other generating company could have been prohibited from presenting assumptions to the rating agencies that it was planning to receive future assets pursuant to an agreement requiring their transfer and that the receipt of such assets should be considered when issuing the ratings for periods following that transfer.

In preparing the rating agency presentation for PWEC's initial credit ratings, Pinnacle West and PWEC followed standard industry practices. This included the hiring of independent market consultants (PA Consulting) and independent engineers (Stone and Webster). The two

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75 Decision No. 61973 at 10.

76 *See* Enron Post-Hearing Brief, Docket E-01345A-98-0473, et al., at 13-14 (August 5, 1999).

77 *Id.* at 14.

78 Decision No. 61973, adopting Section 4.4 of the 1999 Settlement.

parties were hired in August 2000 and worked for approximately six months developing market forecasts (PA Consulting) and performing in-depth reviews of all of the power plants.

The presentation book given to the rating agencies reflected the PA Consulting and Stone and Webster forecasts, as well as Pinnacle West's assumptions including:

- the transfer to PWEC of APS' fossil generation assets in January of 2001 and APS nuclear generation assets by the end of 2002;
- PWEC generation additions of Redhawk units 1, 2, 3, and 4 (2,026 MW total), West Phoenix units 4 and 5 (631 MW total), and the purchase of 72 MW from Nevada Power Company at the Harry Allen plant in Nevada;
- that, post-divestiture, PWEC generation would be dedicated to native load requirements through a transfer pricing agreement ending in 2004 in conformance with Rule 1606(B) or, if deemed necessary, a variance to that rule.

Given the circumstances at the time, Pinnacle West believed these all to be reasonable assumptions. However, it is clearly the last assumption that has caused the most confusion in Decision No. 65796.

As noted above, there was an assumption made for purposes of financial modeling that a purchase power agreement would be used to serve APS' needs through 2004. Under this assumption, for 2001 and 2002 PWEC would supply that generation through a contract with Pinnacle West Marketing and Trading, which in turn would resell the power to APS at a market price. This period was prior to when the competitive bidding requirement in Rule 1606(B) would become effective. For 2003 and 2004, the assumption was that PWEC would continue to sell all of its power to Pinnacle West Marketing and Trading. Pinnacle West Marketing and Trading would provide power to APS at market prices but up to 50 percent of APS' power could be supplied through the competitive bidding process in the Electric Competition Rules.[79]

Thus, under this model, PWEC would sell *all* of its power to Pinnacle West Marketing and Trading and APS would procure *all* of its needs at market prices, including the possibility of 50 percent coming through competitive bidding.[80] It was reasonable to assume that a significant amount of APS' power would be supplied by the fuel-diverse fleet of generation that was being divested by APS pursuant to the Electric Competition Rules. Also, there was no reason for APS to believe that a contract at market prices would not have been considered an "arm's length" transaction. There was, however, never a representation made to the rating agencies that PWEC actually had a signed contract with APS through 2004, or that APS would contract with PWEC in some manner that violated the Electric Competition Rules. Neither was there any representation made that the Commission had approved such an agreement.

[79] *See. e.g.,* PWEC Rating Agency Presentation (February 2001) at p. 12 (specifically referring to the 50 percent competitive bidding requirement in the Electric Competition Rules). This presentation was Panda-TECO Exhibit No. 23 in the proceeding on the Financing Application.

[80] The full output contract between PWEC and Pinnacle West Marketing and Trading for the PWEC generation would have remained in effect regardless of whether APS was being supplied by other parties under the competitive bidding requirement in the Electric Competition Rules.

Executives from Pinnacle West met with the rating agencies to review the presentation book. After the initial meeting, each of the rating agencies followed up with requests for various scenarios "stress testing" the forecasts. Each of the three agencies used its own assumptions in addition to those modeled by PA Consulting, Stone and Webster, and Pinnacle West. Had the rating agencies felt that any of the assumptions were unrealistic, they presumably would have modeled it differently and the financial modeling was, after all, ultimately their responsibility. And, the rating agencies were specifically provided with copies of the Electric Competition Rules and the 1999 Settlement.

After their analysis, contingent investment grade credit ratings were deemed appropriate by each of the rating agencies based on credit metrics for a 20-year horizon. The agencies looked at the minimum fixed charge coverage ratio ("FCCR") as well as the average over that 20-year period. They looked at the FCCRs in the base case that was presented as well as the various stress scenarios. Even had the purchase power agreement modeled in the base case been above or below market, because of its relatively short term of four years, it would have had a minimal impact in evaluating the entire 20-year horizon studied by the agencies.

Later in 2001, the electric utility industry started to experience the difficulties centered around Enron and other merchant generating companies. The bank and debt capital markets became extremely sensitive to any complication in a company's credit picture. Pinnacle West's bankers had been kept apprised of the planned divestiture of the APS generation and the then-planned phased-in approach of first transferring the fossil units and then the nuclear units by the end of 2002. Pinnacle West realized in the fall of 2001 that a transfer of the fossil assets might not occur that year given the recent crisis in California. However, by this time, project financing options were no longer available for Pinnacle West or PWEC, just as they were not for the vast majority of the industry. The Commission initiated its inquiry into the Electric Competition Rules in 2002 and halted the planned divestiture of the APS generation to PWEC, thus rendering the contingent credit ratings moot.

C. APS' Power Procurement

During the hearing on APS' Financing Application there also appeared to be questions raised regarding APS' power procurement. This resulted in an assertion that the "dedication" of the PWEC units to APS' customers "raises the issue of possible intended noncompliance with the Commission's [Electric Competition Rules] and/or possible anticompetitive activity."[81] This general statement is not further clarified nor are any specific legal requirements referenced. Neither allegation is correct. APS never violated, or intended to violate, Rule 1606(B). Nor has either APS or PWEC engaged in "anticompetitive activity" in developing a business strategy designed to protect its customers and shareholders.

No Electric Competition Rule that applied to APS prior to January 1, 2003 required *any* specific action by APS regarding power procurement or limited its options, other than self-building new generation. Under Decision No. 61973, the procurement requirements of Rule 1606(B) were delayed for two-years until the beginning of 2003 so that any procurement

81 Decision No. 65796 at 34, n.18.

activities by APS were not restricted by that rule through the end of 2002. As discussed above, the only interim provision relating to Rule 1606(B) addressed the *supply* of generation from APS (and provided that APS would not discount generation for Standard Offer customers) not the *procurement* of generation by APS. And, because APS' rates were capped during this interim period (and in fact through mid-2004), none of APS' procurement activities could have harmed APS' captive customers because they paid the same amount to APS regardless of where APS' power was obtained.[82] All procurement of Standard Offer supplies between APS and its affiliates occurred lawfully under FERC-approved market-based rate tariffs.

With respect to post-2002 compliance with Rule 1606(B), APS had filed its Request for Partial Variance in October 2001 *requesting* a variance to that rule pursuant to Rule 1614. That request was a lawful and expressly permitted filing based on the belief that customers would be better off under APS' proposal. Any suggestion that a request for a variance believed to be in the public interest shows "possible intended non-compliance" would unlawfully gut the ability of any utility to file for any variance on any rule. Regardless, in April 2002 APS made it clear that if the Commission denied its application the Company would proceed with "good faith compliance with Rule 1606(B) as written."[83] Ultimately, however, the Commission concluded—as APS had argued—that the "wholesale market is not currently workably competitive; therefore, reliance on that market without recognizing its current uncertainty and limitations will not result in just and reasonable rates for captive customers."[84] As a result, the Commission itself decided that Rule 1606(B) needed to be stayed. Thus, the Commission reached *the same conclusion* regarding Rule 1606(B) that APS had argued in its Request for Partial Variance, but chose a different means of addressing that conclusion.

APS never stated that it would refuse to comply with any lawful Commission order. Thus, in the Partial Variance proceeding, APS specifically stated that if the Commission denied the Company's application, APS would proceed with "good faith compliance with Rule 1606(B) as written."

Also, because the Commission had already approved sales from PWEC to APS as in the public interest in the 1999 Settlement, the dedication of the PWEC units to APS' customers is not evidence of "possible intended non-compliance" with the Electric Competition Rules. Under those rules, APS was still required to provide reliable service at just and reasonable rates even after it was required to divest its generation pursuant to Rule 1615(A). APS had significant exposure to a dysfunctional wholesale market because its load was increasingly exceeding the Company's owned generation. Because APS could not itself build generation, Pinnacle West and PWEC constructed the PWEC units to fill the gap left in the Electric Competition Rules regarding the obligation to serve. PWEC installed expensive temporary capacity in APS' service

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82 *See Pinnacle West Capital Corp.*, 91 FERC ¶ 61,290 (2000), *reh'g denied*, 95 FERC ¶ 61,300 (2001).

83 *See* APS' April 19, 2002 Motion for Threshold Determination, Docket No. E-00000A-02-0051, et al., at 3.

84 Decision No. 65154 at 29.

area during the summer of 2001 to maintain reliability during an extremely challenging period in Western United States power markets. And, PWEC (and not APS) voluntarily refrained from selling its newly-constructed units forward into other wholesale markets at lucrative prices because of their dedication to ensure that APS' customer needs were met.

The construction of the PWEC units proved to be extremely advantageous for APS customers. In California, the turmoil of two years of skyrocketing wholesale power costs forced CDWR to buy more than $40 billion in long-term contracts to stabilize California's exposure to the market. The state is now trying to litigate its way out of those contracts. In Arizona, APS was not forced to buy high-priced, long-term capacity because the PWEC units were available to APS customers. Indeed, the results of the recently completed Track B process established that without the PWEC "dedicated" capacity, APS would not be able to reasonably meet its summer requirements in the next few years.

Nothing prohibited other merchant generators that constructed capacity in Arizona from announcing that their capacity was "dedicated" to APS customers. In fact, many took the historically undocumented position during the Track B proceeding that they wanted to serve and had planned on serving APS load. The results of the Track B competitive procurement and the participation of merchant generators in that proceeding demonstrate, however, that none of the merchant generators were willing to assume the risks that PWEC and Pinnacle West assumed in holding back their generation to benefit APS customers.

D. Other Assertions

During the hearing on the APS Financing Application and in Decision No. 65796, certain other issues were raised. The Commission expressed concern about the possible use by Pinnacle West or PWEC of APS generation and captive ratepayers to gain an advantage in the developing competitive environment. The Decision also questioned why APS, rather than PWEC, applied for an air quality permit for the PWEC West Phoenix and Saguaro plants. And, the Chief Administrative Law Judge inquired about how the requirement in Decision No. 61973 that the supply of generation during the two-year extension to Rule 1615 and Rule 1606(B) was addressed in APS' Code of Conduct to ensure that APS did not obtain any advantage over ESPs in retail competition. The latter issue was discussed above in Section IV(B). The two former issues are discussed below.

Pinnacle West Use of APS Generation

PWEC made no "inappropriate" use of the APS assets that either harmed customers, violated the law, or was inconsistent with the 1999 Settlement. In fact, the 1999 Settlement required APS to divest all of its generation to PWEC. Under that requirement, the generation would become subject only to FERC regulation and, to the extent applicable, the Commission's Affiliated Interest Rules. The 1999 Settlement also contained a specific acknowledgement that the generation affiliate formed under Pinnacle West to receive the APS generation would be subject to no more regulation by the Commission than other non-utility owners of generation.[85]

[85] 1999 Settlement at § 4.4.

Given the contractual commitment obtained by APS authorizing the transfer of generation to PWEC, it was entirely appropriate for PWEC to develop a business plan that assumed it would acquire the APS generation assets. There is no Commission regulation or any state or federal law that would prohibit PWEC from making such an assumption, or taking action based on that contractual commitment. Thus, it was appropriate for PWEC to ask the credit rating agencies who were evaluating PWEC post-divestiture to look at how the APS generation would affect its credit rating, and obtain a more favorable rating based on PWEC obtaining such generation that would otherwise be available for the PWEC units on a standalone basis.

There is no Commission regulation or order, or any state or federal law, that would prohibit PWEC from assuming that it would receive the APS generation as required by the 1999 Settlement. In fact, that was the only logical assumption that could PWEC could have made in developing and presenting its business plan.

Likewise, the regulatory body with jurisdiction over wholesale sales has concluded that APS' captive customers were protected and authorized Pinnacle West and its affiliates to sell to each other at market-based rates. Section 4.4 of the 1999 Settlement included specific Commission findings that such sales would benefit consumers, did not violate Arizona law, would not provide APS' generation affiliate with an unfair competitive advantage, and were in the public interest. Moreover, APS' retail rates cannot be increased prior to mid-2004 so there is no way for APS to recover more or less from customers regardless of what actions it takes with Pinnacle West or PWEC prior to that time. Thus, neither PWEC nor Pinnacle West could or have used APS generation in any way to adversely affect captive customers or unfairly compete in the developing wholesale market.

Air Quality Permits

Under the Maricopa and Pinal County air regulatory programs, no person may commence construction or operation of a source of air emissions until the person has obtained any required air permit.[86] A "source" is defined as any "building, structure, facility or installation" that causes or contributes to air pollution.[87] In turn, a "building, structure, facility or installation" is defined as all of the pollutant-emitting activities which (1) belong to the same industrial grouping; (2) are located on one or more contiguous or adjacent properties; and (3) are under common control.[88] Thus, under applicable law, one permit is required for each source.

The United States Environmental Protection Agency ("EPA") has issued a number of interpretive letters and guidance documents addressing when facilities located on contiguous or

[86] *See* Maricopa County Environmental Services Department ("MCESD") Rule 200 § 302; Pinal County Air Quality Control District ("PCAQCD") Rule § 3-1-040.A.

[87] *See* MCESD Rule 100 § 200.99; PCAQCD Rule § 1-3-140.123.

[88] *See* MCESD Rule 100 § 200.26; PCAQCD Rule § 1-3-140.21.

adjacent property constitute one source for air permitting purposes.[89] In these documents, EPA has expressly stated that common control is established through common ownership, meaning a common parent company.[90]

EPA regulations required APS to apply for the air permits for PWEC's West Phoenix and Saguaro plant expansions. PWEC paid APS for all costs associated with these permit applications.

At both the West Phoenix and Saguaro Power Plants, PWEC constructed facilities at locations where APS owned existing generation. Because APS and PWEC are under common control—they are both owned by Pinnacle West—and the facilities belong to the same industrial grouping and are located on adjacent properties, the APS and PWEC units at each site constitute one "source" under applicable law. The air quality regulatory requirements relating to the APS and PWEC units are required to be included in one air permit. Because APS was, and still is, the operator of the facilities, and already held the permit for the West Phoenix and Saguaro Power Plants, APS was required to apply for the amended air permit to add the PWEC units. PWEC, however, paid all costs associated with obtaining the amended air permits at both plants.

An analogous situation exists at the Cholla Power Plant. At that plant, APS both applied for and holds the air permit for all four units, even though Unit 4 is owned entirely by PacifiCorp. In that situation, "common control" exists due to the contractual relationship between APS and Pacificorp, which delegates to APS the authority to operate the plant.

[89] *See, e.g.,* Nov. 27, 1996 letter to Jennifer Schlosstein, Simpson Paper Company, from Matt Haber, EPA Region IX; Nov. 2, 1995 letter to Terry Harris, Knox County Department of Air Pollution Control, from Jewell Harper, EPA Region IV; July 20, 1995 letter to Ron Methier, Georgia Department of Natural Resources, from Jewell Harper, EPA Region IV; Sept. 18, 1995 letter to Peter Hamlin, Iowa Department of Natural Resources, from William Spratlin, EPA Region VII.

[90] *See, e.g.,* Feb. 20, 1998 letter to James A. Joy, South Carolina Dept. of Health and Envtl. Control, from R. Douglas Neely, EPA, Air and Radiation Technology Branch.

VI. CONCLUSION

This Report shows how the industry and electric competition in Arizona has evolved from the first Electric Competition Rules in 1996, through the adoption of the current Electric Competition Rules in 1999 and the 1999 Settlement, to today's debate about wholesale competition rather than retail direct access. This evolution has apparently resulted in perceptions about the Electric Competition Rules, in both their scope and implementation, that do not fit with the historical context.

For example, given the recent debate surrounding Rule 1606(B) and the role of merchant generators who did not participate in the 1999 Settlement proceedings, it is regrettable, although perhaps understandable, that some would read a provision in Decision No. 61973 about the supply of generation during the two-year extension and expect it to reflect the current debate. When looking at the context and the comments filed by intervenors, however, it is clear that the reference was in fact focused on the supply of generation *by* APS, not *to* APS. Similarly, no one questioned that the retail Code of Conduct applied only between APS and APSES at the time it was adopted.

When viewed appropriately, and with the surrounding context, it is clear that APS' actions have been both consistent with the rules, the 1999 Settlement, and other applicable law, including each of the issues identified by the Chief Administrative Law Judge in the APS Financing Application proceeding. In fact, while APS has vigorously debated issues (as have other parties), APS has been active and responsive in implementing the policies of the Commission after the debate has concluded both with respect to the wholesale market and retail competition.

While other parties may differ with APS on the merits of its actions in requesting relief from the Commission on issues with which the Company is concerned, and while the Commission may ultimately disagree with APS on certain requests, it is not illegal to request relief. It was also not a violation of law for APS and its affiliates to pursue a business strategy designed to protect customers and shareholders and prevent what happened to investor-owned utilities in California from occurring in Arizona. That strategy has protected Arizona customers both today and into the future, has protected shareholders, and allowed the debate on electric restructuring to continue in Arizona rather than be painted as a failed experiment like in other places in the Western United States.

GLOSSARY OF TERMS

1999 Settlement - The Settlement Agreement between APS, the Commission and most of APS' customer groups that was signed on May 14, 1999 and approved with some modifications in Decision No. 61973 (October 6, 1999).

A.A.C. - Arizona Administrative Code.

AECC - Arizonans for Electric Choice and Competition.

Affiliate Interest Rules - Codified in A.A.C. R14-2-801 to -806. These state rules govern matters involving public utility holding companies.

AISA - Arizona Independent Scheduling Administrator. Required under A.A.C. R-14-2-1609(D), the AISA was designed to help provide nondiscriminatory transmission access on an interim basis until a Regional Transmission Organization became functional in Arizona.

APS - Arizona Public Service Company.

APSES - APS Energy Services is a retail Electric Service Provider as defined in A.A.C. R14-2-1601(15).

Biennial Transmission Assessment - A biennial report prepared by Commission Staff addressing the adequacy and reliability of Arizona's existing and planned transmission system.

Blue Book - A report published in 1994 by the California Public Utilities Commission setting forth a plan for retail electric competition and the restructuring of the electric industry in California.

CAISO - California Independent System Operator. An independent system operator established to provide open and non-discriminatory electric transmission services in California.

California Power Exchange - A now-bankrupt California power auction forum established to facilitate wholesale energy trades.

CC&N - Certificate of Convenience and Necessity. A certificate issued by the Commission granting a utility exclusive rights to provide services in its "service territory."

CDWR - California Department of Water Resources. The agency in California that took over power procurement on behalf of investor-owned electric utilities in 2001.

Code of Conduct - A Commission-approved code required by A.A.C. R14-2-1616. It currently applies to conduct between an Affected Utility like APS and its Competitive Retail Electric Affiliates, which for ASP is APSES. FERC also has a Code of Conduct requirement.

Commission - The Arizona Corporation Commission.

Company - Arizona Public Service Company.

Consumer Information Label - A label provided to customers on request and discussed in A.A.C. Rule R14-2-1617 that outlines a variety of information about Standard Offer and competitive electric service.

DASR - Direct Access Service Request. An electronic form used to communicate between UDCs and ESPs.

Desert STAR - Desert Southwest Transmission and Reliability Operator. The predecessor of WestConnect. Desert STAR was a product of the initial effort to develop an independent system operator or regional transmission organization in Arizona.

Electric Competition Rules - A.A.C. R14-2-1601 to -1617.

Environmental Portfolio Standard - A renewable resources portfolio program that is codified at A.A.C. R14-2-1618.

EPA - The United States Environmental Protection Agency.

ESP - Electric Service Provider. Under the Electric Competition Rules, ESPs obtain competitive CC&Ns and provide Competitive Services to retail customers under bilateral or multilateral contracts.

FCCR - Fixed Charge Coverage Ratio. A ratio used by financial analysts in determining the creditworthiness of a company.

FERC - The Federal Energy Regulatory Commission. FERC has exclusive jurisdiction over interstate transmission and sales of power for resale.

Financing Application - The application filed by APS in Docket No. E-01345A-02-0707 and which was approved by Decision No. 65796 (April 4, 2003).

Generic Stranded Costs Order - Decision No. 60977 (June 22, 1998). Addressed stranded cost recovery for Affected Utilities.

H.B. 2663 - House Bill 2663, enacted by the Arizona Legislature in 1998 to address retail electric competition.

ISO - Independent System Operator, which is similar to an RTO.

Must-Run Generation Units - Local generation that is necessary to maintain the reliability of the electric system when external or remote generation cannot be used to meet load requirements in an area.

OASIS - Open Access Same-Time Information System. Instituted by FERC Order 889, an OASIS provides real-time information to transmission users.

OATT - Open Access Transmission Tariff. The OATT is the tariff required by FERC Order 888, to implement wholesale open access.

Pinnacle West - Pinnacle West Capital Corporation, the holding company and parent entity of APS, APSES and PWEC.

PWEC - Pinnacle West Energy Corporation, the wholesale generation affiliate of APS and a subsidiary of Pinnacle West.

Request for Partial Variance - The application filed by APS in October 2001 pursuant to A.A.C. R14-2-1614 in Docket No. E-01345A-01-0822. The Commission stayed this application in Track A.

RTO - Regional Transmission Organization. An RTO is discussed in FERC Order 2000 and FERC's Standard Market Design initiative. It is intended to provide for regional operation and development of transmission systems to facilitate wholesale competition.

RUCO - The Residential Utility Consumers Office.

Schedule 10 - Implements APS' rules and regulations for direct access service, as well as addressing the business relationship between APS and Electric Service Providers offering service in APS' distribution service area.

SIC - System Incremental Costs.

SMA - Supply Margin Assessment. An interim method being used by FERC to evaluate whether an owner of generation has market power in a given market.

SRSG - Southwest Reserve Sharing Group. An organization established to allow sharing of contingency reserves among participants to realize more efficient and economic power system operations while maintaining the reliability of the interconnected system.

SSG-WI - Seams Steering Group-Western Interconnection. This group is addressing seams and interface issues amongst the three Western United States RTOs—WestConnect, the CAISO, and RTO West.

Standard Offer Customers - Customers who continue to purchase electric generation from an incumbent utility.

TEP - Tucson Electric Power Company.

Track A - The proceeding resulting from the Generic Investigation into the Electric Competition Rules in Docket No. E-00000A-02-0051.

Track A Decision - Decision No. 65154 (September 10, 2002).

Track B - The proceeding addressing competitive solicitations by APS and TEP in Docket No. E-00000A-02-0051, *et al.*

Track B Decision - Decision No. 65743 (March 14, 2003).

TTC - Total Transfer Capability. This is the amount of capacity available on a transmission line.

UDC - Utility Distribution Company. Under the Electric Competition Rules, a UDC was to provide Standard Offer service and unbundled distribution service to customers, but would not own any generation.

WAPA - Western Area Power Administration. One of several federal agencies tasked with the responsibility of marketing electricity generated by facilities owned and operated by the federal government.

WECC - Western Electricity Coordinating Council. Formed in April 2002 by the merger of the Western Systems Coordinating Council, the Southwest Regional Transmission Association and the Western Regional Transmission Association, the WECC is responsible for coordinating and promoting electric system reliability for the Western United States' power grid.

WestConnect - An RTO that is being developed for Arizona and the Southwest.

WSCC - Western Systems Coordinating Council. The WSCC was the precursor to the WECC.

Schedule JE[illegible]B

APS 1999 Long Range Forecast
Summer Loads & Resources (MW)

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
	SYSTEM DEMAND FORECAST										
1	TOTAL DEMAND FORECAST	5291	5487	5420	5607	5773	5987	6171	6368	6562	6754
2	TOTAL INTERRUPTIBLE	200	200	200	200	200	200	200	200	200	200
3	MANAGED PEAK DEMAND	5091	5287	5220	5407	5573	5787	5971	6168	6362	6554
4	ANNUAL LOAD GROWTH %	2.2	3.8	-1.3	3.6	3.1	3.9	3.2	3.3	3.1	3.0
	GENERATION RESOURCES										
5	APS EXISTING GENERATION	3987	3987	3987	3987	3995	3995	3995	3995	3995	3995
6	CUC GENERATION (NOGALES) (A	42	42	0	0	0	0	0	0	0	0
7	W. PHOENIX RECOMMISSION	96	96	96	96	96	96	96			
8	W. PHOENIX REPOWER	0	0	0	0	0	0	0	195	195	195
9	W. PHOENIX NEW CC 4	0	118	118	118	118	118	118	118	118	118
10	SEASONAL VARIATION	(77)	(77)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)
11	CAPACITY ON MAINTENANCE	0	0	0	0	0	0	0	0	0	0
12	TOTAL	4049	4167	4126	4126	4134	4134	4134	4233	4233	4233
	PURCHASED POWER RESOURCES										
13	SRP - TERRITORIAL (B)	267	274	281	288	295	302	310	318	326	334
14	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62
15	PACIFICORP CONTRACTS (B)	480	480	480	480	480	480	480	480	480	480
16	SHORT-TERM PURCHASES	845	603	50	0	0	0	0	0	0	0
17	TOTAL PURCHASES	1654	1419	873	830	837	844	852	860	868	876
	SALES COMMITMENTS										
18	SALE-BACK	0	273	273	273	273	0	0	0	0	0
19	MARKET SALE		0	0	399	1325	2214	2673	2708	2522	2561
20	TOTAL SALES	0	273	273	672	1598	2214	2673	2708	2522	2561
	DISTRIBUTED GENERATION										
21	COGEN/DISTRIBUTED (C)	5	10	15	19	22	24	25	26	26	26
22	RENEWABLE	2	3	10	10	10	10	10	10	10	10
23	TOTAL	7	13	25	29	32	34	35	36	36	36
24	NEW GENERATION CCs and C	0	0	0	0	0	0	0	0	0	0
25	Increased PV Share		367	367	367	967	967	967	967	967	967
26	Increased FOUR CORNER 4-5 SHARE		104	104	104	208	208	918	918	918	918
27	Increased NAVAJO SHARE		169	169	169	169	589	589	589	589	589
28	W. PHOENIX NEW CC	0	0	250	250	250	250	250	250	250	250
29	HEDGEHOG NEW CC	0	0	0	500	1000	1500	1500	1500	1500	1500
30	OTHER PROJECTS	0	0	250	250	250	250	250	500	500	750
31	TOTAL	0	640	1140	1640	2844	3764	4474	4724	4724	4974
32	TOTAL RESOURCES [12+17+23+3	5710	6239	6164	6625	7847	8776	9495	9853	9861	10119
33	PLANNED RESERVES [32-3-20]	618	679	672	547	677	775	852	978	978	1005
34	PLANNED RESERVES %	14%	14%	14%	10%	11%	11%	11%	12%	12%	12%

		2010	2011	2012	2013	2014	2015	2016	2017	2018
	SYSTEM DEMAND FORECAST									
1	TOTAL DEMAND FORECAST	6954	7157	7361	7568	7774	7981	8196	8415	8631
2	TOTAL INTERRUPTIBLE	200	200	200	200	200	200	200	200	200
3	MANAGED PEAK DEMAND	6754	6957	7161	7368	7574	7781	7996	8215	8431
4	ANNUAL LOAD GROWTH %	3.1	3.0	2.9	2.9	2.8	2.7	2.8	2.7	2.6
	GENERATION RESOURCES									
5	APS EXISTING GENERATION	3995	3995	3995	3995	3995	3995	3995	3995	3995
6	CUC GENERATION (NOGALES) (A	0	0	0	0	0	0	0	0	0
7	W. PHOENIX RECOMMISSION									
8	W. PHOENIX REPOWER	195	195	195	195	195	195	195	195	195
9	W. PHOENIX NEW CC 4	118	118	118	118	118	118	118	118	118
10	SEASONAL VARIATION	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)
11	CAPACITY ON MAINTENANCE	0	0	0	0	0	0	0	0	0
12	TOTAL	4233	4233	4233	4233	4233	4233	4233	4233	4233
	PURCHASED POWER RESOURCES									
13	SRP - TERRITORIAL (B)	342	351	360	368	378	387	397	407	417
14	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62
15	PACIFICORP CONTRACTS (B)	480	480	480	480	480	480	480	480	480
16	SHORT-TERM PURCHASES	0	0	0	0	0	0	0	0	0
17	TOTAL PURCHASES	884	893	902	910	920	929	939	949	959
	SALES COMMITMENTS									
18	SALE-BACK	0	0	0	0	0	0	0	0	0
19	MARKET SALE	2592	2622	2650	2674	2701	2726	2521	2313	2106
20	TOTAL SALES	2592	2622	2650	2674	2701	2726	2521	2313	2106
	DISTRIBUTED GENERATION									
21	COGEN/DISTRIBUTED (C)	26	26	26	26	26	26	26	26	26
22	RENEWABLE	10	10	10	10	10	10	10	10	10
23	TOTAL	36	36	36	36	36	36	36	36	36
24	NEW GENERATION CCs and C	0	0	0	0	0	0	0	0	0
25	Increased PV Share	967	967	967	967	967	967	967	967	967
26	Increased FOUR CORNER 4-5 SHARE	918	918	918	918	918	918	918	918	918
27	Increased NAVAJO SHARE	589	589	589	589	589	589	589	589	589
28	W. PHOENIX NEW CC	250	250	250	250	250	250	250	250	250
29	HEDGEHOG NEW CC	1500	1500	1500	1500	1500	1500	1500	1500	1500
30	OTHER PROJECTS	1000	1250	1500	1750	2000	2250	2250	2250	2250
31	TOTAL	5224	5474	5724	5974	6224	6474	6474	6474	6474
32	TOTAL RESOURCES [12+17+23+3	10377	10636	10895	11153	11413	11672	11682	11692	11702
33	PLANNED RESERVES [32-3-20]	1031	1058	1084	1112	1139	1165	1165	1165	1165
34	PLANNED RESERVES %	12%	12%	12%	12%	12%	12%	12%	12%	12%

Notes:
(A) Owned by another utility, but available to meet APS system load.
(B) The reserves for this capacity are provided by the seller.
(C) Third party owned and operated.

APB_WPB 15/8

Generation Marketing Plan

Immediate Opportunity

- Market excess generation through 2010, given:
  - ⇒requirement to cover native load
  - ⇒current assumptions on loads and resources
  - ⇒targeted enterprise spark spreads

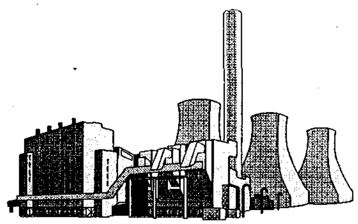
1/2

Generation Marketing Plan

Volume

- Excess capacity is defined as that volume over and above the native load forecast capacity, calculated on a monthly basis
- Excess capacity is available for forward sale
- Once a forward sale is executed, that volume is no longer available to serve native load
- Excess capacity is recalculated upon a 'Trigger Event'

2/2

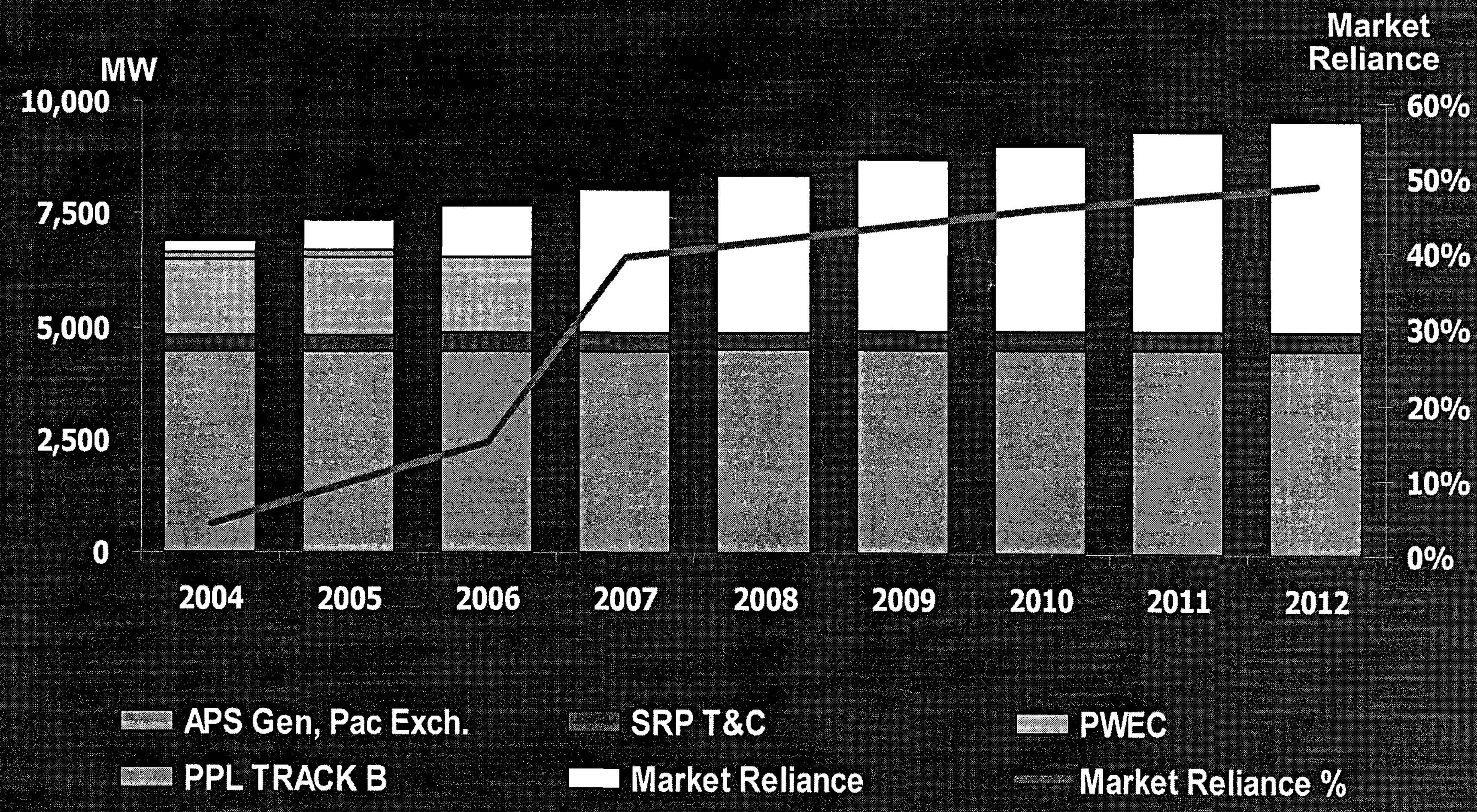


Resources

	2001	2002
• **Existing Generation**	3982	4497
Renewable	9	13
• **Additions**		
Upgrade of existing CC&CT	107	-
Reactivate WPhx Steam 4&6	96	-
WPhx CC 4	114	-
Temporary WPhx CT's - 5 units	99	(99)
Temporary Saguaro CT's - 5 units	99	(99)
Redhawk CC 1&2	-	988
Subtotal	515	790
• **Long-term Contracts**		
Pacificorp Exchange	480	480
SRP	336	343
Subtotal	816	823
• **Short-term Contracts**	1176	638
• **Total Resources**	6498	6761

Schedul ED-4RB

APS Supply & Demand



APS-2R

EXHIBIT

APS-2R
admitted

REBUTTAL TESTIMONY OF STEVEN M. WHEELER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

Table of Contents

REBUTTAL TESTIMONY OF STEVEN M. WHEELER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Steven M. Wheeler. I am Executive Vice President of Customer Service and Regulation for Arizona Public Service Company ("APS" or "Company"). Please note that my present title is somewhat different from that in my Direct Testimony and reflects organizational changes announced in September of 2003. The major difference is that Customer Service has been placed under my ultimate supervision and many of the planning functions now directly report to Don Robinson.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony will first provide an overview of the Company's reaction to the unexpectedly negative recommendations of Utilities Division Staff ("Staff"), and to a lesser extent, to those of certain intervenors. As part of that same Section, I summarize the major themes of our entire rebuttal case.

I will then respond to specific statements and recommendations made by Staff witness Harvey Salgo, as well as intervenor witnesses Kevin Higgins (Arizonans for Electric Choice and Competition or "AECC"), Dr. Joseph Kalt and Jeffrey D. Tranen (Arizona Competitive Power Alliance or

"ACPA") concerning the appropriate ratemaking criteria by which the Arizona Corporation Commission ("Commission") should evaluate the Company's request to acquire and rate base Pinnacle West Energy Corporation's ("PWEC") Arizona generating assets. In this latter context, I will address three of the questions posed by Commissioner Gleason in his letter dated September 5, 2003 and respond to the criticisms by Dr. Kalt and Mr. Tranen of the Company's pending Request for Proposals ("RFP") process and of my Direct Testimony concerning the results of the Company's Track B power solicitation during the spring of 2003. I also correct Mr. Tranen's evaluation of the Company's must-run situation in the Metro-Phoenix area.

My Rebuttal Testimony explains the critical need for the Commission to determine in this proceeding the going-forward regulatory framework relating to resource planning and acquisition whereby APS can and should meet its public service obligation to Standard Offer customers. In that regard, I am in agreement with the Residential Utility Consumer Office ("RUCO") as to the need for establishing these standards, although I disagree with RUCO's specific recommendations to reinstitute the integrated resource planning ("IRP") process as it existed in the early 1990s, to end customer choice in the context of this APS rate proceeding, and to immediately or arbitrarily reverse course on the Commission's long-time support of the Company's participation in a regional transmission organization ("RTO").

Next, I will discuss and rebut assertions made by RUCO witness Marylee Diaz Cortez, Mr. Higgins and Staff consultant Lee Smith about the status of and the extent of alleged "benefits" received by APS under the 1999 APS

Settlement Agreement ("1999 APS Settlement"), which was approved and adopted by the Commission in Decision No. 61973 (October 6, 1999). Such discussion of the 1999 APS Settlement leads to my next topic, which is the Commission's "preliminary inquiry" into the Company's past relationship with PWEC and Pinnacle West Capital Corporation ("Pinnacle West").

Then, I will respond to the testimonies of Mark E. Fulmer (Constellation New Energy/Strategic Energy or "CNESE") and Ms. Diaz Cortez concerning the retention of retail competition in Arizona and in the case of Mr. Fulmer, APS' position on equal transmission access for load serving entities within the Company's transmission control area. Finally, I present a summary of the Company's revised test period jurisdictional revenue requirements that incorporates all of the adjustments reflected in the Rebuttal Testimony and attached Schedules of APS witness Donald Robinson.

Q. BEFORE YOU SUMMARIZE YOUR REBUTTAL TESTIMONY, DO YOU HAVE ANY GENERAL OBSERVATIONS ON THE RECOMMENDATIONS FILED BY STAFF AND INTERVENORS?

A. Yes. Without meaning to diminish the significance of other areas of my Rebuttal Testimony, I would like to offer three introductory points.

First, despite the significant discussion contained in Staff and Intervenor testimony, no evidence (as contrasted with conjecture or speculation) has been produced demonstrating that there is any superior alternative to rate-basing the PWEC assets. Although I concede that no one, including APS, can accurately predict future fuel prices, spark spreads, customer demand, market developments, etc., the overwhelming economic evidence, when taken as a whole and when coupled with the equitable and reliability considerations described in our case, demonstrate that the APS rate-basing proposal is in the best interest of the Company's customers, will not harm the competitive market, and is an appropriate response to the Commission's change of policy in its Track A Order.

My second observation is that the overall rate level recommendations from those parties who chose to make them (Staff and RUCO) were not accompanied by any attempt to measure the financial and service level impact of those recommendations on the Company and its customers on a going forward basis. This is a critical omission, and I would hope that the Commission will carefully consider the Company's rebuttal testimony demonstrating that the significant rate decreases recommended by those parties will harm the Company in a manner that is both undeserved, but, more importantly, will significantly and adversely impact the ability of the Company to respond to the challenges of serving one of the fastest growing areas of the country.

My third and final preliminary observation is that no party comprehensively addressed the long-term reliability and regulatory issues facing the Company that must be resolved if APS is to respond to its customers' expectation of reliable, efficient and fairly priced service in the future. These issues, which I will describe later, have either been ignored completely or handled in a way that provides neither closure nor appropriate resolution.

II. SUMMARY OF REBUTTAL TESTIMONY

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Yes. The Staff recommendations in this proceeding are, both individually and collectively, the most extreme I have seen in my thirty years of practicing and appearing before this Commission. As is indicated by Company witnesses Donald Brandt, Mr. Robinson and Steven Fetter, these recommendations would, if adopted by the Commission, destroy the financial integrity of APS and its parent, Pinnacle West. Furthermore, they would place customers at risk and could prove damaging to the state as a whole.

APS has presented a comprehensive rebuttal case that addresses each of the principal recommendations of Staff and intervenors on a factual, regulatory and policy basis. I believe that rebuttal will convincingly demonstrate the following:

- The PWEC generation assets were prudently planned and constructed to serve APS and provide APS customers with benefits that both exceed their cost and which are greater than could be expected from any plausible alternative, market-based or otherwise.

- The proposed cost-of-equity recommendations of Staff and intervenors are so low as to deny APS the ability to reasonably attract or retain the equity capital needed to maintain a prudent capital structure and finance the capital additions necessary to serve a rapidly-growing service territory and state.

- If APS is to engage in prudent resource planning and resource acquisition, the "rules of the game," that is, its objectives, the means by which such objectives can be satisfied, and the criteria to be applied by regulators in determining our success in meeting those objectives, must be removed from underneath the present cloud of uncertainty. The Commission should, in this regard, reaffirm the traditional regulation of APS as a vertically-integrated utility having a traditional obligation to serve at cost-based rates.

- Restoration to APS of the $234 million in prudently-incurred and already previously authorized (by the Commission) regulatory assets written off in conformance with the 1999 APS Settlement Agreement, along with unification at APS of the generation used to serve APS under a common regulatory regime and full recovery of costs incurred to follow the restructuring requirements of the Commission are appropriate and equitable actions in light of the Track A Order's determination to "change direction" with regard to such restructuring notwithstanding the commitments made in the 1999 Settlement and the Company's detrimental reliance on such commitments.

- APS has made appropriate and consistent pro forma adjustments to the historical test period required by Commission rule. These adjustments follow both the dictates of that rule and established Commission policies regarding the need for relative certainty in both the existence and quantification of the pro forma adjustment requested and the identification of those other aspects of test period operations that would be necessarily affected by such adjustment.

- The policies followed by the Commission for many years with regard to depreciation and nuclear decommissioning expense continue to be the prudent and reasonable approaches to both capital recovery and the future removal of the Palo Verde plant (and other generation) from service in an environmentally-responsible and safe manner, which also does not leave the financial responsibility for such recovery and removal to those future customers that received no benefits during the life of the capital asset in question.

- The Company's cost allocation methodology, and its resultant revenue allocation and rate design recommendations, reflect proper ratemaking principles, including the need to minimize non-cost-justified rate differentials while maintaining a degree of rate continuity over time and within established customer classes.

- APS has been a reliable provider of quality service at reasonable and stable prices, and it is a valuable corporate citizen. Its financial collapse, as is the likely result of adopting either the Staff or RUCO recommendations, will have severe short-term and long-term economic consequences for its customers and the communities it serves.

Since the PWEC assets would have been constructed by APS as utility-owned generation but for what the Court of Appeals has recently found to be an invalid Commission regulation, it is appropriate for such PWEC generation to be evaluated for ratemaking purposes in the same manner as other APS generating assets. To suggest, as have Staff and some intervenors, that the Commission ignore both the history of how APS and its affiliates got to their present circumstances and selectively adopt previously rejected notions of "economic excess capacity" simply because the term "market value" has now been attached to this discredited concept, is in the Commission's own words, "simply unfair." And the fact that APS witness Ajit Bhatti's analyses, as well as the market evaluation testimony of Dr. William H. Hieronymus, demonstrate that no such "economic excess capacity" exists with regard to the PWEC generation (because it is more than likely that the market value of those assets is in excess of cost), does not alter the Company's fundamental objection to Staff's and intervenors' conceptual approach to establishing the ratemaking value of the PWEC plants to be acquired by APS and included as part of the APS rate base.

The contention that APS has somehow tainted the ongoing Company resource RFP by requesting a "regulatory out" provision for such proposals is inaccurate and unsupported by the actions of the ACPA's own members participating in such RFP. The RFP does contemplate a "regulatory approval" provision that is both a practical necessity given the Company's financial circumstances and the uncertain state and federal regulatory climate and a requirement that is quite common in other jurisdictions. Indeed, the PWEC assets are themselves undergoing an infinitely more onerous "regulatory approval" process as part of this rate case. And although APS believes that the intervenors, and to some extent Staff, should not have made either the RFP or the current market value of the PWEC Arizona generation issues in this case, the proposals received in this

RFP from actual market participants validate the original conclusion of Mr. Bhatti and Dr. Hieronymus that such assets are a cost-effective resource addition for the Company and its customers. They also are another reminder that the merchant power industry has not yet evolved to the point where APS and this Commission can reasonably rely upon the wholesale market as the sole source of the future resource additions APS and its customers will need and demand.

The Track A order clearly established that APS was no longer heading down the path of divestiture and restructuring required by the Electric Competition Rules and the 1999 Settlement. What is not clear, and which was left unresolved by the Track A and Track B orders, was what path APS would be expected to follow now. APS believes that a vertically-integrated utility, with an appropriate mix of utility-owned generation, long-term contracts with credit-worthy entities, and shorter term market purchases, each of which is reflected in rates on a cost-of-service basis, provides the best combination of reliability, flexibility and price stability for customers. Others, clearly opposed to a more vertically-integrated APS, effectively urge the Commission to return to its original path of restructuring based on wholesale market reliance, albeit perhaps at a slower, more incremental basis. This is a critical policy decision for this Commission, one which will affect the Company, its customers and Arizona for years to come and which due to APS' pressing resource needs, cannot be further postponed. With no firm, clear and consistent "rules of the game," and in the absence of Commission authorization for specific discrete resource additions, APS is placed in an untenable position of being required to play in a game when its objectives, its rules and its scoring system are not sufficiently clear.

The Commission has unilaterally altered key elements of the 1999 APS Settlement in a manner clearly harmful to the Company and its affiliates, while other provisions negotiated in good faith by the Company have not yet been implemented. Thus, the contention that APS has not been harmed by these actions is just plain wrong. And to use these failures of performance by other parties to such Agreement as the basis for attempting to now terminate the Settlement merely compounds APS' status as the aggrieved party.

The Commission's subsequent efforts to staunch the bleeding by addressing the immediate and grievous financial situation created by the Track A Order and the small amount of divestiture-related dollars Staff and AECC offer in this proceeding neither represent any meaningful compensation to APS for the alteration of the Settlement nor do they resolve the underlying issue of bifurcation first identified in July of 2002 in an open letter to the Commission in the Track A proceeding from Pinnacle West's Chairman, William J. Post, and discussed at length by the Company's CEO, Jack Davis, in his Rebuttal Testimony.

Staff's comments regarding the "preliminary inquiry," although resulting in no recommended regulatory actions, clearly serve to impugn the Company's integrity, something it has taken pride in maintaining throughout the scandal-ridden Western energy debacle of 2000-2001, as evidenced by the Federal Energy Regulatory Commission's ("FERC") dismissal earlier this year of all allegations of wrongdoing against APS. As both I and other APS witnesses will explain, Staff's conclusion that APS violated either the "spirit" or "letter" of the 1999 Settlement, the Electric Competition Rules and/or its Commission-approved Code of Conduct are wholly unsupported and indeed completely contradicted by the available contemporaneous evidence, as is also discussed by the Company's CEO, Jack Davis. The specific Staff analysis of the six issues identified as components of the "preliminary inquiry" represents unsupportable re-interpretations of prior Commission orders and regulations in a manner that ignores or severely distorts their original meaning and intent.

The issue of whether or not to retain or modify Arizona's retail competition rules is not, in my opinion, the proper subject of this rate proceeding. This is especially the case because the Commission has both established a separate docket for just such a purpose (Docket No. E-00000A-02-0051) and designated a specific body, the Electric Competition Advisory Group ("ECAG"), to accomplish that purpose. To the extent the Commission does wish to address these sorts of issues in this rate case, the Commission should not interpret the Company's insistence that we establish certain "first principles" concerning the goals of retail electric competition as unreasonable intransigence. These "first principles" are spelled out in the Company's filed Comments in the Docket cited above and include: the need to establish policy priorities for when policies are in conflict; a belief that simplicity works best and that regulatory consistency is essential; the importance of funding new mandates and of demanding accountability from those asking for customer funding of such mandates; the preservation of the financial health of incumbent "Affected Utilities"; and acknowledgement of the primary role of the federal government in the area of wholesale electric competition, and more specifically in the development and regulations of RTOs.

The Commission needs to carefully investigate and evaluate for itself claims of retail competition's "success" in other jurisdictions. Such "successes" may take credit for exogenous factors having little if anything to do with retail competition and have often been either short-lived or simply confuse activity with achievement. Moreover, any decision by the Commission to end retail competition, as recommended by RUCO, should not jeopardize the Company's collection of both those costs previously incurred to prepare for restructuring and retail competition or to otherwise implement the Electric Competition Rules and related Commission orders, as well as those ongoing costs that have been more or less built into the system as a result of such Rules and orders.

The Company had accepted, at least in modified form, some of the Staff and intervenor proposed adjustments to its test period revenue requirement. Mr. Robinson and APS witnesses Laura Rockenberger and Pete Ewen have suggested additional items not reflected in the Company's original revenue requirement, but which are now appropriate to consider given the other recommendations being offered in this proceeding. After netting both sets of adjustments, the Company's revised increase in annual jurisdictional base revenue requirements is now $185 million as set forth in Schedule SMW-1RB. However, APS is <u>not</u> asking the Commission to alter the Company's original request for an annual base increase of $166.8 million.

III. <u>OVERALL COMPANY REACTION TO THE STAFF AND INTERVENOR RECOMMENDATIONS AND SUMMARY OF APS REBUTTAL CASE</u>

Q. WHAT WAS THE COMPANY'S REACTION WHEN IT FIRST READ THE STAFF AND INTERVENOR TESTIMONY?

A. The same as it is now – shock, dismay and virtual disbelief. And as is discussed in the testimony of the other APS witnesses referenced in my Summary, this was the universal reaction of the entire financial community – or at least that portion of the financial community which follows the electric utility industry.

Q. WHY WAS THE RESPONSE TO THESE RECOMMENDATIONS SO NEGATIVE?

A. There were a number of reasons. First of all, like APS, the analysts and rating agencies can do the math and see the resultant loss of financial strength for APS and Pinnacle West. However, there was also the tenor of especially the Staff testimony that caught both the Company and Wall Street off guard. After the resolution in Decision Nos. 65434 (December 3, 2002) and 65796 (April 4, 2003) of the immediate financing crunch Pinnacle West found itself in following the Track A order, which resulted in the execution of the Principles of Resolution between APS and Staff, we, and apparently the financial community, anticipated that Staff would give thorough consideration to all relevant aspects of the unification of the PWEC generation at APS in the present rate proceeding. Given the Staff testimony on this point, it is difficult to see where any such comprehensive consideration was undertaken. Moreover, despite the assurances of the Commission in both the Track A and Track B decisions that these decisions would not prejudice the potential rate base treatment of PWEC's Arizona generation, Staff and intervenors pointedly use PWEC's Track B contract with APS as a primary basis for their recommendations against that very ratemaking treatment.

Q. WAS THE COMPANY'S CONCERN AND THAT OF THE FINANCIAL COMMUNITY LIMITED TO THE PWEC RATE BASE

ISSUE OR EVEN TO THE TENOR OF THE STAFF RECOMMENDATIONS?

A. Of course not. It was the cumulative impact of a uniquely (even by national standards) low recommended ROE, the largest reduction in depreciation allowances in Arizona history, a reversal of Staff's position of just a few months ago on implementation of a power supply rate adjustment mechanism, a departure from Commission policies of the past decade or longer on nuclear decommissioning, and the complete absence of any discussion about or analysis of the Company's rapidly escalating power supply deficit. These specific recommendations were added to Staff's apparent refusal to address the significant harm suffered by APS and its affiliates as a result of the Track A Order, a harm that is both undeniable and wholly separate and apart from the issue of whether such Order was in some sense, the "right" thing for the Commission to do. As can be seen by the financial community reactions quoted in Mr. Brandt's Rebuttal Testimony, there was an inescapable conclusion that a utility that had successfully weathered the most severe crisis in this industry's history with both its integrity and financial condition intact was now being effectively "punished" for those very accomplishments.

Q. **DO YOU BELIEVE THAT STAFF, AND EVENTUALLY THE COMMISSION, NEED TO BALANCE THE INTERESTS OF BOTH SHAREHOLDERS AND CUSTOMERS IN MAKING ITS REGULATORY RECOMMENDATIONS AND DECISIONS?**

A. Absolutely. And it is obvious to me that one cannot achieve that degree of balance without the sort of rigorous analysis of financial and capital market consequences as is discussed by Mr. Brandt and other of the Company's rebuttal witnesses. Just as important as the balancing of arguably competing interests (shareholder vs. customer) is the recognition by Staff and the

Commission that regulation need not be, and most often is not, a "zero sum" game where every utility "gain" represents a corresponding "loss" to its customers. Indeed, the relationship of a utility with its customers is far more often symbiotic than adversarial. APS cannot survive without its customers, and the modern society of which our customers are a part cannot survive without a financially viable electric provider.

Q. DO STAFF'S AND RUCO'S RECOMMENDATIONS PLACE CUSTOMER SERVICE AND RELIABILITY AT RISK?

A. Unfortunately, the answer to both is yes. As is discussed in Mr. Brandt's Rebuttal, APS would have great difficulty, and incur significantly higher costs, in meeting the Company's incremental debt and equity capital needs given the severe deterioration in APS' and Pinnacle West's financial condition and may also need to seek refinancing of existing credit arrangements on unfavorable terms.

Q. ARE THESE INCREMENTAL CAPITAL NEEDS SIGNIFICANT?

A. Yes. The 10-Year Transmission Plan the Company recently filed with the Commission calls for over $1 billion in high-voltage transmission alone. I mention this because I am responsible for trying to implement that Plan, a task that will be significantly more difficult and expensive under the recommendations of Staff and RUCO. Mr. Brandt provides a more comprehensive look at APS external capital needs in his Rebuttal Testimony, which are anticipated to be well over $ 2 billion over the next 10 years.

Q. WOULD THERE ALSO BE OPERATIONAL CHALLENGES RESULTING FROM THE COMPANY'S FINANCIAL DISTRESS?

A. Yes. Adding additional service personnel to meet the Company's fast-growing customer base, or even retaining existing personnel, would be equally difficult if not impossible under such circumstances. Other operational constraints would impact APS power and fuel procurement as both the potential number of willing (to do business with APS) counterparties decrease and the level of credit support demanded by those who will increases. Although most apparent in the areas of fuel and power procurement, there would be a general tightening in the vendor credit terms, if any, offered to APS. As we have seen elsewhere in the West, once a utility starts down that slippery slope to financial distress, its options are increasingly limited and its ongoing costs of remaining in business continuously increasing. Although he does not use the term "death spiral," it is precisely that sort of cascading financial collapse that is outlined by Mr. Brandt.

Q. WOULD ONLY APS AND ITS CUSTOMERS SUFFER FROM A FINANCIALLY-WEAKENED APS?

A. No. The experience in our neighboring states of California and Nevada show that there is very likely to be considerable damage to the overall economy from the inability of weakened electric providers to protect customers or even protect themselves. The adverse rate impacts on customers in those jurisdictions are well known. But, they are only the most obvious fallout. Alan Maguire, a Phoenix-based consultant familiar with the impact of distressed businesses on their local community, testifies on this point as part of the Company's overall rebuttal presentation.

Q. IN YOUR SUMMARY, YOU HIGHLIGHTED SOME OF THE PRIMARY AREAS OF THE COMPANY'S REBUTTAL CASE. COULD YOU ELABORATE?

A. Yes, although I am far from the subject matter expert on these issues. I do, however, have overall responsibility for this Application and for the witnesses that explain and justify it to this Commission. Thus, I will provide a very brief explanation of the bullet points set forth in my Summary.

PWEC Units in APS Rate Base: The PWEC Units were prudently planned and constructed. They do provide and have provided APS customers with reliable capacity and energy. Although these two factors have historically been the criteria for rate base inclusion in Arizona, there have been suggestions in this case that the Commission selectively apply a "market value" test to this issue. That would ignore the fact that but for actions by the Commission, the PWEC assets would have been constructed at APS and, in fact PWEC would never have existed. That being said, Mr. Bhatti and Dr. Hieronymus' analyses provide compelling and singular evidence that the "market value" of the PWEC generation is significantly in excess of the cost asked by the Company to be included in rates.

Cost of Equity: The cost of equity capital recommendations of Staff and intervenors are exceedingly low by any measure. They reflect flawed methodologies, biased or unsupported assumptions, and invalid comparisons of APS to so-called "comparable" utilities. Moreover, the Company would not earn even these miniscule returns under either the Staff or RUCO recommendations, with return on equity falling to a mere 5.5% in 2005, the first full year of their proposed rate reductions. The fallout of such a financial catastrophe would include a plunge to "junk" credit status for the first time in the Company's over 100-year history, and the loss of marketable credit, including access to commercial paper and tax-exempt markets. Interest costs alone would increase by over $100 million per year over the next 10 years – and perhaps most ironically, that increase would be more than the revenue requirements associated with the PWEC assets for the same period, but with nothing to show for such increased costs in the way of reliable service. Thus, the Company's ability to raise the capital needed to maintain and expand service to one of the fastest growing service areas in the United States would be seriously compromised, and Arizona would be well on its way towards repeating the debacles of California.

Restoration of the Write-Off Required by the 1999 APS Settlement: The $234 million write-off represented a real loss of APS shareholder value that would not have occurred but for the 1999 APS Settlement. This was a loss in value not compensated for by any other benefit actually realized by the Company from that 1999 APS Settlement. Neither has APS "over-earned" from its customers as a result of the 1999 APS Settlement. Thus, given the failure of the Company to receive that for which it negotiated in the first instance, there is no compelling or even persuasive reason of regulatory policy or in equity why the write-off should not be restored to APS.

Depreciation: Staff consultant Michael Majaros' recommended $47 million reduction in the Company's current authorized depreciation expense marks the first significant issue involving APS depreciation practices in many decades. Much of this reduction is created by deferring for future customers the costs of removing assets serving current customers in a manner that is contrary to Commission rule and in a manner inconsistent with the practices of all other utilities regulated by this Commission. Any capital asset's eventual removal costs are being accrued each day the asset is in service and ought to be paid by those customers served by that asset. The balance of Mr. Majaros' adjustment is the product of assigning to APS plant amongst the longest service lives, and hence the lowest depreciation rates, of any major electric utility in this country. Recovery of capital is a critical source of internally-generated funds for any utility but is especially so for a utility such as APS that already has large external capital needs and will very significantly aggravate the overall inability of APS to function under the Staff and RUCO recommendations in this proceeding.

Nuclear Decommissioning: Staff challenges fundamental decommissioning assumptions adopted by this Commission in 1988 and 1991 and continued without controversy for well over a decade. The first of those assumptions, simply put, is that APS will restore the Palo Verde site to as close to its original state as possible. It is a principle that all the Palo Verde participants and their regulators have likewise accepted. The Company believes it would be unwise and impractical to seek to now adopt Staff's "good enough" standard for decommissioning. The second, and more significant from a funding basis, is the lengthening of the decommissioning period for Palo Verde Unit 2. As noted in Mr. Robinson's Rebuttal Testimony, this is contrary to established Commission practice, prior Commission orders, and will cost future APS customers more than Staff hopes to save for current APS customers.

Pro Forma Adjustments: The Commission's own rate case rule calls for pro forma adjustments under appropriate circumstances. The Commission's prior rate decisions have established the three criteria for such adjustments: (1) they must be "known," not in the sense of absolute certainty but to the degree that their existence is more than probable; (2) they must be measurable, not to a scientific certainty but to the extent that including them is likely to make the test period more representative of the period in which rates will be established than would not including them; and (3) they must be reconcilable with the test period's other items without serious issues of mismatching, not to the point of requiring a whole new test period but to the point where the adjustment recognizes other directly-related items (e.g., do not adjust sales without including the additional costs attributable to such sales). Each of the Company's adjustments meets these criteria and should be adopted.

Allocation Methods and Rate Design: APS allocation methods are based on the Company's unquestioned status as a predominantly summer-peaking utility. Allocation methodologies that do not follow the pattern of cost-causation only result in additional cross-subsidies and improper price signals to consumers about the cost of the services they consume. And, although Staff and certain of the intervenors have made rate design proposals which the Company can support, the balance of the APS-proposed rate design are based on sound principles of cost-causation, administrative simplicity, conformance with regulatory requirements and rate continuity.

IV. RATEBASE STANDARD FOR THE PWEC ASSETS

A. General

Q. HOW HAS THE COMMISSION TRADITIONALLY VALUED GENERATING PLANTS IN THE COMPANY'S RATE BASE?

A. The Commission has taken the average of the plant's original cost less depreciation ("OCLD"), also sometimes referred to as book value, and the plant's reconstruction cost new less depreciation ("RCNLD"). For that reason, the Commission's Standard Filing Requirements ("SFR") for rate cases (A.A.C. R14-2-103) require applicants to provide both OCLD and RCNLD information for all the assets proposed to be included in rate base.

B. Use of Market Value

Q. DO THE SFR REQUIRE AN APPLICANT TO PROVIDE EVIDENCE OF AN ASSET'S CURRENT MARKET VALUE?

A. No. Thus, I do not understand how either the ACPA witnesses or Mr. Salgo can legitimately criticize APS for not providing such evidence in its pre-filed direct testimony.

Q. ASIDE FROM THE SFR, HAS THE COMMISSION EVER UTILIZED MARKET VALUE TO DETERMINE THE RATE BASE VALUE OF ANY APS ASSET?

A. Not to my knowledge and certainly not in the thirty or so years I have been associated with the Company as either its outside counsel or an officer.

Q. DO ANY OF THESE WITNESSES PROVIDE THE COMMISSION WITH ANY EVIDENCE OF THE MARKET VALUE OF EITHER THE PWEC ASSETS OR OF ANY ALTERNATIVE SOURCE OF LONG-TERM POWER SUPPLY?

A. The pre-filed testimonies of ACPA witnesses Mr. Tranen and Dr. Kalt, as well as AECC witness Mr. Higgins, offer no evidence on either subject. When APS asked them and other parties opposing rate-basing in discovery to provide such evidence, some essentially refused (ACPA) and others indicated they had none (AECC). Surprisingly, both Staff and RUCO presented evidence in their testimonies that actually supported the rate basing of the PWEC units, but chose to disregard that evidence in their final recommendation. The specifics of those Staff and RUCO analyses are discussed by Mr. Bhatti and Dr. Hieronymus in their Rebuttal Testimonies.

Q. HAS THE COMMISSION BEEN ASKED TO UTILIZE ESTIMATES OF A GENERATING PLANT'S MARKET VALUE IN PREVIOUS APS RATE PROCEEDINGS?

A. Yes. During the years that the Palo Verde Generating Station's three units were being incorporated into APS rate base, there were several efforts to claim that it should be assigned a "fair value" equal to some estimate of market value that was significantly lower than even the original cost of Palo Verde, let alone the "fair value" as calculated using the traditional Commission valuation method I described above. Because the wholesale market was a far different animal in the 1980s than today, those "market value" estimates (of what was then termed "economic excess capacity") were based on what the proponent believed was a more economic alternative (when viewed in hindsight) than was the construction and operation of Palo Verde – usually a coal plant of similar size and vintage. This is described as the "replacement cost" methodology later in my rebuttal. Also, as in this case, these parties did not propose to consistently use the same valuation methodology for the balance of the generating plants APS was proposing to include in rate base. However, I would hasten to add that at least the opponents of Palo Verde used the correct analytical approach to determine the difference in the current value of their alternative to that of Palo Verde, which was life-cycle present value of future revenue requirements. They did not try to confuse the issue by talking about the timing of "cross-over" points or compare the first three years' revenue requirements of a thirty-plus year asset to the three years' revenue requirements of a three-year asset, as have the RUCO, AECC, and Staff witnesses in this proceeding.

Q. WHAT DID THE COMMISSION DO IN THESE PRIOR INSTANCES?

A. The Commission unequivocally rejected such a selective valuation method:

> It would take many pages for us to discuss the numerous arguments for and against "value-based pricing," "risk sharing," and "market-based pricing," and we have no doubt that any number of experts could analyze PV-1 [Palo Verde Unit No. 1] and arrive at widely varying conclusions of the plant's economic "worth." Indeed, this was certainly the case herein. Fortunately, it is not necessary for us to examine in minute detail the many assumptions which formulate the foundation for the otherwise objective-looking calculations of present worth and opportunity cost. After reviewing the various proposals presented, we find ourselves in agreement with APS witness [Alfred E.] Kahn that, as formulated, these proposals are <u>simply unfair</u>." [Emphasis supplied.]

Decision No. 55228 (October 9, 1986) at 33. The Commission again rejected the same argument in Decision No. 55931 with regard to Palo Verde Unit No. 2. In both instances, the Commission was no doubt concerned both with the lack of Arizona precedent for treating any measure of an asset's "market value" as its "fair value" and, perhaps more fundamentally, with the inconsistency of valuing some utility assets one way and other assets a different way, which would have been the same sort of regulatory inconsistency decried in Dr. Kenneth Gordon's Direct and Rebuttal Testimony. And although the Commission did not have the benefit of the Court's guidance when it entered the cited decisions on Palo Verde in 1986 and 1988, its holding was, in a sense, prophetic of the words of Chief Justice Rehnquist in *Duquesne Light Co. vs. Barasch*, 488 U.S. 299, 315 (1989):

> Consequently, a State's decision to arbitrarily switch back and forth between [valuation] methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investments at others would raise serious constitutional questions. _

C. Prudent Investment and Used and Useful

Q. DOES THE COMMISSION REQUIRE THAT ASSETS REPRESENT A PRUDENT INVESTMENT TO BE INCLUDED IN A UTILITY'S RATE BASE?

A. "Prudent investment" is really a valuation issue and not an eligibility criterion as regards rate base inclusion. For example, if $100 was invested in an asset that should reasonably have been built or acquired for $90, given what was known at the time the investment was made, then the asset would not be entirely excluded from rate base, but included at the lower $90 figure.

Q. ARE INVESTMENTS PRESUMED TO BE "PRUDENT"?

A. Yes, SRF Regulation 103 (A) (3) (l) defines "Prudently invested" to mean:

> Investments which under ordinary circumstances would be deemed reasonable and not dishonest or obviously wasteful. All investments shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments were made.

Q. HAS ANY PARTY TO THESE PROCEEDINGS OFFERED "CLEAR AND CONVINCING EVIDENCE" THAT THE PWEC ASSETS SHOULD NOT HAVE BEEN BUILT "WHEN VIEWED IN THE LIGHT OF ALL RELEVANT CONDITIONS KNOWN OR WHICH IN THE EXERCISE OF RESONABLE JUDGMENT SHOULD HAVE BEEN KNOWN, AT THE TIME SUCH INVESTMENTS WERE MADE"?

A. No. At most, they offer conjecture about what might have been constructed contemporaneous to the West Phoenix, Redhawk and Saguaro plants, or complain about alleged omissions from Mr. Bhatti's and Dr. Hieronymus' analyses of the prudence issue in their Direct Testimonies. These alleged "deficiencies" are addressed by those Company witnesses in their rebuttal. However, the Commission should keep in mind that APS is under no obligation to present any evidence on prudence unless and until another party has presented "clear and convincing evidence" to dispute such the presumption set forth in the Commission's regulation.

Q. SHOULD THE "PRUDENT INVESTMENT" TEST BE APPLIED AS IF APS IS TODAY MAKING AN ENTIRELY NEW INVESTMENT TO, IN A SENSE, "PURCHASE" THE PWEC ASSETS?

A. No. That would totally ignore the history of how APS, PWEC and Pinnacle West got to the present circumstances, which I, Mr. Davis, Dr. Hieronymus and others have testified to in great detail. In other words, it would ignore the unchallenged fact that but for the actions of the Commission, the PWEC assets would have been built at APS and their prudence evaluated using the information then available. It would further ignore the purpose for which these assets were constructed, which was to serve APS – also the subject of much testimony in these proceedings.

Q. DON'T MR. BHATTI'S AND DR. HIERONYMUS' ANALYSES SHOW THAT EVEN UNDER TODAY'S CIRCUMSTANCES, AND IGNORING FOR THE MOMENT WHAT YOU DESCRIBE IN YOUR DIRECT TESTIMONY AS THE EQUITABLE ARGUMENTS FOR INCLUDING THE PWEC ASSETS IN RATE BASE, THE PWEC ASSETS REPRESENT A PRUDENT LONG-TERM INVESTMENT FOR APS AND ITS CUSTOMERS?

A. Yes. That does not change my fundamental objection to and opposition of a valuation methodology that both differs from that applied to other APS generation under what are similar circumstances, or which <u>would</u> have been similar circumstances but for the Commission's generation divestiture policy, and which ignores the equitable circumstances discussed in my Direct Testimony and to which I refer in the preceding answer.

Q. ARE THE PWEC ASSETS "USED AND USEFUL"?

A. Yes. These assets are clearly being used by APS and will be useful in providing capacity and energy to APS customers. The issue of whether some alternative to the PWEC assets would be "more used" or "more useful," although fully addressed by other APS witnesses, goes at best to the issue of rate base <u>valuation</u> and not rate base <u>inclusion</u>. Moreover, "used and useful" is clearly not a universal "litmus test" for rate base inclusion because I am aware of several instances in which the Commission has included construction work in progress ("CWIP") in rate base, including the Company's rate base, when such CWIP obviously could not meet any literal requirement that it be currently "used and useful."

Q. ACPA WITNESS TRANEN CLAIMS THAT THE PWEC WEST PHOENIX UNITS MAY NOT BE "USED AND USEFUL" EVEN THOUGH DESIGNATED AS "MUST-RUN" BY APS. DO YOU AGREE?

A. No. Mr. Tranen uses the Reliability Must Run ("RMR") report prepared last year to argue that there are "other options" and "low cost approaches" to using PWEC's West Phoenix units for necessary in-Valley local generation after the Track B contracts expire. Specifically, he asserts that a static VAR compensator with an annualized cost of $2.4 million would resolve APS' Valley operating needs or that APS could submit an RFP for Valley must run needs. This analysis is wrong.

To support his discussion of post-Track B needs, Mr. Tranen used last year's RMR Study which covered 2003 through 2006. He ignored the more recent RMR Study that was filed in January 2004, which provided analysis through 2012. In that more recent RMR study, the development of which included various ACPA members, the Valley transmission limits in 2008 were determined to be thermal, not voltage related. Such thermal limits cannot be solved by static VAR compensators. Instead, several new 500 kV transmission lines would be needed into the Valley at a cost of at least several hundred million dollars. When the cost and the siting impacts of such lines are compared to the amount of RMR generation needs, local generation clearly makes more sense than transmission upgrades even before considering the economic benefits of the West Phoenix units themselves, which is addressed in Mr. Bhatti's Rebuttal Testimony.

Mr. Tranen's argument that the West Phoenix units can provide economical supply both inside and outside the Valley load pocket is correct—the fact that these units can provide both economical system generation and cost-effective RMR supplies when needed is a benefit to APS and provides significant operational flexibility. APS has never argued that the sole reason the units should be rate based is because of their ability to provide in-Valley local generation, as Mr. Tranen appears to suggest. Also, Mr. Tranen's assertion that new simple cycle generation could be sited and constructed inside the Valley load pocket before summer 2007 clearly shows that he is unfamiliar with the siting process and recent cases in Arizona. Even if it were possible to obtain siting approval for and construct new plants in the Valley, RMR generation needs were specifically included in APS' Track B solicitation in 2003, and no bids for RMR supply were submitted. Finally, Mr. Bhatti's analysis of that "option" clearly demonstrates that it would result in higher costs to APS customers.

D. Commissioner Gleason's Questions from Letter of September 5, 2003

Q. ARE YOU RESPONDING TO ALL OF COMMISSIONER GLEASON'S QUESTIONS AS SET FORTH IN HIS LETTER DATED SEPTEMBER 5, 2003?

A. No. I will respond to the first three of those questions, while Dr. Hieronymus will address the last two. And even at that, I will have to refer Commissioner Gleason to those APS witnesses with more technical subject matter expertise in asset evaluation to supplement my own testimony.

Q. HOW SHOULD THE COMMISSION CALCULATE THE MARKET VALUE OF A POWER PLANT?

A. Well, as you can see from some of my earlier discussion, I don't believe the Commission should be calculating market value at all, at least unless it is willing and able to apply the same valuation method "across-the-board." As can be seen in Mr. Bhatti's Rebuttal Testimony, this would very significantly increase the Company's rate base even before consideration of the PWEC assets. Having clearly restated the Company's fundamental objection to selective application of a market value test, let me respond to the question this way:

There are several methods that can and have been used in various contexts. I will briefly discuss each in turn.

The primary methods relied upon by APS, Staff and RUCO, which are the only parties that have even attempted to actually value the plants, are the present worth of the net cash flows generated by the PWEC assets or alternatively, the present value of revenue requirements from rate-basing the PWEC assets compared with one or more alternatives. The former is called the discounted cash flow or "DCF" method. Mr. Bhatti uses this form of analysis as does RUCO witness Schlissel. Ms. Jaress also endorses the DCF valuation methodology at page 2 of her Addendum to the Direct Testimony of Linda A. Jaress. The premise of DCF is simply that the value of any commercial property is equal to the present value of the net revenue (revenue less costs) stream derived from such property. Although conceptually sound, projecting future revenue and cost streams is more easily said than done, and as can be seen from the passage I quoted earlier from the Commission's 1986 order on Palo Verde, involves a number of assumptions that cannot be easily verified, if at all. This is less of a problem, however, when making comparative evaluations to rank the value of various options because all or most of the necessary assumptions can be held constant for each option. Also, the DCF methodology assumes that all benefits can be monetized, i.e., reduced to an objectively quantified dollar figure. However, some obviously important benefits of a particular generating plant or set of generating plants such as reliability, fuel diversity, relative lack of environmental impact, operational flexibility, etc., cannot be so quantified.

A second method is so-called "comparable sales." Dr. Hieronymus and Mr. Bhatti discuss this method in their rebuttal. However, since the buyer may well be using its own DCF analysis to determine how much it is willing to pay, you are, in a sense, merely substituting the assumptions of one DCF calculation for those used by another. And again, there is the problem of incomplete or inaccurate monetization of non-monetary benefits. But, given the innumerable factors that can affect individual asset sales (financial distress of the seller, the other options available to specific buyers, timing of sale, terms of sale, etc.) the more fundamental problem is finding truly "comparable sales" in the utility context. This problem is highlighted because of the existence of distressed assets, which by definition, are not being offered for fair market value. This difficulty of determining "market value" in this manner for utility property is one that has been explicitly noted by our own courts:

> It would be almost impossible for a public utility to have a market, value, as that term is commonly used, since such things are not routinely and commonly sold on the public market. But even so, there would be many elements and considerations involved in arriving at the price to be paid for a public utility that would be of no concern in arriving at the fair value. [*Arizona Corporation Commission v. Arizona Water Company*, 80 Ariz. 198, 207, 335 P2d 412, 415 (1959)]

A third method is the use of RCN. This is the method most consistent with both past Commission practice in finding "fair value" and is called for by the Commission's own SFR regulation. Mr. Bhatti provided the RCN value for the PWEC assets in his Direct Testimony (Bhatti Direct Testimony at Schedule AB-5).

Finally, there is a variant to RCN called "replacement cost new." Unlike RCN, which attempts to replicate today the specific asset or assets, "replacement cost" looks at what it would take to provide the analogous service, albeit perhaps through a different means or even using a different technology. The comparison of Palo Verde to a coal plant that I discussed earlier is an example of an earlier attempt to use this valuation methodology, as would a comparison of a utility-owned power plant to a long-term PPA. Because it is a comparative analysis, it avoids some of the problems of forecasting future revenue streams (DCF) from a single asset or single set of assets. It is less subjective than "comparable" sales, but still involves subjectivity in determining what a reasonable surrogate might be for the original asset being valued and likewise attempts to monetize any differences between the original asset and the replacement asset. For example, a coal plant may serve the same base load function as a nuclear plant, but may not bring the same degree of fuel diversity, regulatory risk or environmental benefit. A simple-cycle gas turbine may be able to replace the capacity and energy provided by a combined-cycle unit for native load customers, but it is less efficient, is less able to generate off-system sales revenues for the benefit of those same native load customers, and is more difficult to site from an environmental standpoint. Mr. Bhatti does, however, present a comprehensive "replacement cost" analysis in his

Rebuttal Testimony. These are compared on the basis of present value revenue requirements, which I alluded to earlier in my rebuttal. This is similar to the comparison undertaken by Mr. Salgo, as well.

One final method would be to auction off the asset or assets in question. That, however, has several problems, one practical and others conceptual, as a means of determining market value. On the practical side, once you have sold off the asset, it is, by definition, no longer available to serve APS customers, which was why you were trying to find its market value in the first place. And if you make the auction "with reservation," i.e., the seller can match the highest offer, this will tend to affect the price offered by others. Finally, the mere fact that the seller is forced to offer its asset for sale at a time and in a manner not of its choosing may depress the likely bids.

Q. IF THE COMMISSION SHOULD LOOK AT THE PLANT'S CURRENT MARKET VALUE INSTEAD OF THE ORIGINAL COST TO BUILD THE PLANT, HOW CAN THE COMMISSION DETERMINE THE MARKET VALUE?

A. I won't repeat my underlying objection to this departure from prior Commission practice, and much of my immediately prior answer is responsive to this question as well. I would add this admonition, however. Market value is <u>not</u> the value set on an asset or assets by a distressed seller. Rather, "fair market value" is generally considered the <u>highest</u> price a property would bring if exposed for sale in the open market.

Q. WHAT POWER PLANTS ARE ON THE MARKET THAT CAN SERVE ARIZONA CONSUMERS?

A. Although I discuss the responses to our 2003 RFP later in my Rebuttal Testimony, it is hard to know whether there are yet other plants available without knowing the often confidential commitments to in-state or out-of-state buyers by those generators that did not respond to the RFP. One may wish to also ask the members of ACPA this same question. APS can only go by what responses it received to its December 2003 RFP. Attached as Schedule SMW-2RB is a list of those respondents to the RFP that offered to discuss, with varying degrees of firmness, an asset sale to APS or long-term PPAs backed by specific plants. I would note that, as indicated on Schedule SMW-2RB, APS originally received two additional offers from the same party, both of which were later withdrawn.

E. The Company's December 2003 RFP and Track B

Q. WHY DID APS ISSUE AN RFP IN DECEMBER OF 2003?

A. As noted in the RFP itself, the Company has a large and growing capacity need. Mr. Davis discusses both the scope of the problem and the inherent risks it presents in his Rebuttal Testimony. The specifics of the reasons for both the scope and timing of that RFP were fully discussed both in the Company's Response of December 24, 2003 to a Motion by ACPA and during the Procedural Conference on such Motion of January 6, 2004. I will not repeat them here. I would add that the RFP itself was filed with the Commission at the request of the Commission's Chief Administrative Law Judge in Docket No. E-00000A-02-0051.

Q. IS APS INSISTING ON A "REGULATORY OUT" PROVISION AS PART OF THE RFP AS ALLEGED BY ACPA (TRANEN TESTIMONY AT 19)?

A. No. In fact, we are not "insisting" on anything in the sense that APS was unwilling to either receive or consider firm non-conforming bids during the RFP. Most, if not all, of the bids received were non-conforming in one respect or another. However, even in the Company's draft asset purchase agreement and its draft PPA, which were a part of the RFP documentation, there was no "regulatory out" provision. There was instead a distinctively different "regulatory approval" clause.

Q. IS THE DIFFERENCE SIGNIFICANT?

A. Very much so, because the requirements and impact of each are quite different. Under a typical "regulatory out" clause, which is most often associated with long-term PPAs and not asset purchases, the parties enter into a contract and begin to transact business pursuant to that contract. As it relates to a PPA, the seller begins to provide and the buyer begins to accept power deliveries. This may go on for years without incident. However, if the buyer has a "regulatory out" provision in the agreement, it may at any time in the future cancel the agreement without penalty or damage if its regulatory agency refuses at such future date to allow the buyer to collect all or part of the contract price from the buyer's customers. That, of course, is unlikely to ever happen when market prices exceed the contract price and very much more likely to happen when market prices are below the contract price.

A "regulatory approval" provision merely means that regulators much approve the purchase <u>before</u> any money, assets or power changes hands. This normally takes only a few months, if not less, and is generally required because the buyer and/or seller need some regulatory approval for either the transaction itself or to borrow the money for the transaction. Other times there is uncertainty as to one or the other party's authority to enter into a transaction and/or the regulatory treatment of such transaction, which leads to the need to resolve that uncertainty before such a large commitment is made. Both the buyer and seller are obviously subject to some regulatory uncertainty during the approval period, but neither has irrevocably committed itself to the deal during such period, which is also a far shorter period than either the term of the PPA or the useful life of the asset, and this period can be further managed by requiring that the transaction close within a specified time. "Prior approval" requirements are common, and are followed in, for example, the states of Nevada, Colorado, Kansas, Florida, Indiana, Iowa, and New Jersey.

Q. HAS APS REQUESTED PRIOR REGULATORY APPROVAL FROM THIS COMMISSION FOR PREVIOUS LONG-TERM PPA'S OR POWER PLANT ACQUISITIONS?

A. APS received Commission approval of both its long-term PPA (and its subsequent amendment, most recently in 1998) with SRP and its 30-year PPA with PacifiCorp. *See* Decision Nos. 29505 (March 13, 1956); 57459 (July 11, 1991) and 61526 (February 19, 1999). The Commission is also presently entertaining a request for pre-approval of long-term natural gas transportation agreements as part of its *Notice of Inquiry on Natural Gas Infrastructure* ("Gas Infrastructure NOI").

Although APS has constructed generation plants for which it received Certificates of Environmental Compliance and financing authorization from the Commission, APS has never previously sought to purchase generation assets the size or financial significance of those solicited by this RFP. Also, this is the Company's first utility generation acquisition since the Track A Order, which as I explain later in my Rebuttal Testimony, has caused some uncertainty as to how the Commission expects or even will permit APS to secure needed generation resources on a going forward basis. The last thing APS needs is more generation that will not be allowed to serve customers on the same regulated basis as its existing generation.

Q. WOULD SOME REGULATORY APPROVAL BE REQUIRED WHETHER OR NOT EXPLICITLY SET FORTH IN THE PROPOSED ASSET PURCHASE AGREEMENT?

A. Yes. Even in the absence of this regulatory uncertainty at the state level, APS would still need Commission authority to issue debt to finance any asset purchase. And such purchase could also require FERC approval. With FERC closely monitoring the acquisition of generation by vertically-integrated utilities, whether or not involving an affiliate, it could be more difficult to obtain any FERC approval without a prior Commission finding that the acquisition was prudent and in the public interest.

Q. DID THE NEED FOR REGULATORY APPROVAL AFFECT THE PRICES OFFERED TO APS IN THE RFP?

A. We have seen no evidence of that, and ACPA offers none - only the unsupported "opinion" of its witnesses, none of which were, I believe, actually involved in the RFP bidding. I would therefore rather rely on the actual bids received and the representations of actual bidders.

Q. DO ANY OF THE CRITICISMS MADE BY ACPA OF YOUR DIRECT TESTIMONY'S ASSESSMENT OF TRACK B (TRANEN TESTIMONY AT 20-21) ALSO APPLY TO THE RFP?

A. No, although I will respond to those criticisms shortly. The RFP was explicitly for long-term resources. As discussed above, the RFP did not even have the partial "regulatory out" provision used for longer-term bids in Track B, which itself would not have been necessary had Staff supported or the Commission adopted the "regulatory approval" language urged by APS. The fact that PWEC was, in essence, locked into some variant of the Company's rate base proposal as its *de facto* bid rather than being allowed to submit a higher bid in response to the RFP, could not have logically affected any other bidder except to exert <u>downward</u> pressure on their bids, although evidently not much downward pressure given the actual economics of the bids received.

However, and not withstanding the out-of-context quotes from the Independent Monitor's Report in Mr. Tranen's testimony, my Direct Testimony concerning Track B was and is 100% accurate. We did get an unexpectedly low number of "net bids" (i.e., bids that were not mutually exclusive) from non-PWEC participants, even though APS allowed every manner of non-conforming bid to be offered, including those that rejected the provision on regulatory approval. We did not get any bids from existing owners of generation within the Phoenix load pocket except from PWEC or any offers to build the transmission needed to bring outside resources into the Valley. The delay in effectuating the Track B process did cost APS many millions of dollars, and the $70 million "savings" figure cited so often is, frankly, meaningless without answering the question "savings from what." And bottom line, if APS had accepted every non-mutually exclusive bid from every non-affiliate, it would not have satisfied the Commission-determined "contestable load" for even one year.

Q. DID THE PARTIAL "REGULATORY OUT" PROVISION IN THE TRACK B CONTRACTS FOR DELIVERIES AFTER 2005 CAUSE FEWER NON-PWEC BIDDERS AND HIGHER NON-PWEC BIDS?

A. Again, I saw no evidence that it did. And, the Independent Monitor did not conclude that it did. The Independent Monitor merely reported that some of the bidders had made such a claim:

> This provision [the regulatory out for deliveries after 2005] appears to have been acceptable to the marketers that submitted bids. However, it was identified as one reason some bidders chose not to provide bids for power to be supplied after 2005. [Independent Monitor's Final Report on Track B Solicitation of May 27, 2003 at 45-46]

Given that parties could and did propose to eliminate the provision as part of their Track B bids and also that no non-PWEC bidder offered to reduce its bid if such provision were eliminated, it is difficult for me to accept that a few bidders' unsupported observations establishes as fact such a sweeping generalization as is being made by Mr. Tranen.

Q. WHILE WE ARE ON THE SUBJECT OF TRACK B, IS THE SUGGESTION BY STAFF AND INTERVENORS THAT THE APS/PWEC TRACK B CONTRACT IS ITSELF AN ARGUMENT AGAINST RATE BASE TREATMENT OF THE PWEC ASSETS CONSISTENT WITH THE TRACK A ORDER'S PRONOUNCEMENT CONCERNING THE CONNECTION, IF ANY, TO BE DRAWN BETWEEN TRACK B AND ITS RATE-BASING DETERMINATION IN THIS PROCEEDING?

A. No. The Track A Order specifically indicated that the actions being taken by the Commission would not prejudice the eventual Commission decision as to whether to rate base the PWEC Arizona assets: "In authorizing this proceeding [Track B], we are not predetermining the relative merits of the [rate-base] issues to be addressed." Decision No. 65154 at 33-34. Staff's repeated observations about needing to preserve, apparently at all costs (quite literally, given Mr. Bhatti's analysis demonstrating that foregoing rate-basing for the last two years of the APS/PWEC Track B contract will result in higher costs to customers) the APS/PWEC Track B contract ignore that Commission directive.

Q. HAVE THE ACPA WITNESSES PROVIDED ANY EVIDENCE THAT THEIR CLIENTS ARE READY AND WILLING TO MEET APS CUSTOMER NEEDS IN A RELIABLE, COST-EFFECTIVE MANNER?

A. No. They point to situations elsewhere in the West in which utilities have either voluntarily or been compelled to seek new resources from the market. The fact that they may have succeeded in making deals of some sort tells this Commission nothing about the economics of the underlying transactions or the likelihood that the suppliers can or will be able to deliver under the terms agreed upon in the years ahead. As I later discuss in the context of retail access, it is important not to confuse activity with achievement, let alone success.

But given the results of Track B, the present Company RFP and the economic analysis presented by Mr. Bhatti and Dr. Hieronymus of long-term market prices, it should come as no surprise that ACPA and the individual merchant intervenors have not presented even anecdotal evidence that the wholesale market is now a safe place for APS customers to entrust their future or that the resource planning equivalent of "working without a net" (in the form of a strong asset-backed resource plan) is anything other than a high-risk undertaking for the Company. Similarly, their refusal to provide such evidence during discovery or their claims that such evidence is somehow "irrelevant" are to me reminiscent of the car salesperson that wants to talk about the car's features and not the price.

Q. HAVE ACPA AND OTHERS MADE THE RFP AND THE RFP RESULTS AN ISSUE IN THIS CASE?

A. Yes. In fact, all the statements made about the Company's failure to "market test" this or provide "market value evidence" of that in the testimonies of ACPA witnesses Dr. Kalt (Kalt Testimony at 14) and Mr. Tranen (Tranen Testimony at 17), as well as Mr. Salgo (Salgo Testimony at 13), RUCO witness Mr. Schlissel (Schlissel Testimony at 28), AECC witness Mr. Higgins (Higgins Testimony at 23), and finally, Staff witness Ms. Jaress (Jaress Addendum to Direct Testimony at 3) have done precisely that. This has placed APS in an exceedingly difficult situation. It can not respond to these charges or respond to them only on the conceptual and policy levels or solely through computer modeling of the market, thus perhaps leaving the false inference that the actual RFP results do not support the rate-basing of the PWEC assets. Or APS can provide the Commission with this information to use as it finds appropriate. In this latter case, APS needs to also attempt to preserve the confidentiality of both the bids and the plant information provided by the bidders, especially during the still ongoing negotiation process.

Q. HOW CAN THE COMMISSION RESOLVE THIS CONUNDRUM?

A. One solution, and that originally proposed in the Company's Response to the ACPA Motion that led to the present situation, is to rule that the PWEC's assets' market value is irrelevant to the rate base issue. This would require the Commission to strike some of the testimony in this proceeding, including that filed by the Company in rebuttal to Staff and intervenors.

An alternative answer, and that chosen by the Company in the absence of guidance from the Commission as to the relevance of market value evidence (the Procedural Order of January 8, 2004 expressly reserved any ruling on the relevance of the RFP), is to provide some high-level information on a non-confidential basis, similar to the Report filed on January 27, 2004 in conformance with the January 8th Procedural Order. In addition, Mr. Bhatti has conducted analyses of the actual bids, without attribution to any specific bidder, both as against the PWEC rate-base proposal and in comparison to the Company's computer modeling of market values used for its DCF and replacement cost studies. To further preserve bidder confidentiality and to prevent those participating in the RFP from gaining an advantage in that process through their access in this proceeding to the Company's specific internal economic analysis of their own bids, Mr. Bhatti has submitted portions of his Rebuttal Testimony under seal, and APS has provided them to Staff and intervenors on a confidential and/or redacted basis.

Q. COULD YOU GIVE AN OVERVIEW OF THE RESULTS OF THE RFP?

A. Yes. There are several broad observations and conclusions to be drawn from the bids received and the Company's analysis of those bids, as is discussed in the Rebuttal Testimony of Mr. Bhatti:

i. the PPAs offered would be consistently and substantially more costly to APS and its customers over their term than would an asset purchase and subsequent rate-basing for an identical term of years, even before consideration of the costs associated with the additional credit support that would be required for many of the proposed PPAs. Such support (for example, through letters of credit) would be necessary to protect APS and its customers from the default risk inherent in all long-term agreements, but which is especially acute in the merchant power industry;

ii. none of the firm asset purchases offered (excepting that offer which was later withdrawn) was comparable in size or type to the PWEC assets;

iii. the pricing of the PPAs under the RFP was consistent with the Company's modeling using the GEMAPS program described in Mr. Bhatti's Direct Testimony;

iv. no bidder suggested that the "regulatory approval" provision materially affected its bid; and,

v. in sum, the RFP did not elicit any "fire sale" bargains.

Q. WHAT USE SHOULD THE COMMISSION MAKE OF THE INFORMATION YOU HAVE PROVIDED AS WELL AS THAT OF MR. BHATTI?

A. As I have indicated previously, I believe that traditional criteria should be applied to the PWEC assets in determining whether and how to include them in the APS rate base rather than some estimate of current "market value." Moreover, there are also strong equitable reasons for including the

PWEC assets in the Company's rate-base. However, I do find it reassuring, and I hope the Commission finds it reassuring, that the APS Resource Planning tools are fundamentally sound in their analytical ability and that the PWEC assets will provide long-term value for APS customers irrespective of who built them or why they were built.

V. RESOURCE ACQUISITION

Q. WHAT ISSUES ARE BEFORE THIS COMMISSION REGARDING THE COMPANY'S FUTURE RESOURCE ACQUISITION ACTIVITIES?

A. There are key policy issues that are fundamental to many of the assertions made by other parties in this proceeding. They concern questions about the Company's status as provider of last resort and whether we are required or allowed to acquire new "steel in the ground" in addition to other resources in order to fulfill this responsibility in a prudent manner. And if the answer to the latter question is "yes," what will be the ratemaking criteria for such newly constructed or acquired generation? Lastly, for whom (all customers, including those that can or have chosen alternative suppliers, or only a subset of such customers) should APS be planning to acquire long-term resources, whether they are new plants, PPAs, or a combination of the two? The Company believes that it is important for the Commission to resolve these issues in this proceeding and provide direction for the future, which is critically needed for such important questions. Simply put, APS asks the Commission to restate or otherwise confirm that:

- APS has the obligation and right to evaluate and effectuate the construction or acquisition of utility-owned generation as part of its overall resource planning and acquisition functions
- Any such new utility-owned generation resources, as well as purchased power agreements, will be evaluated for ratemaking purposes using the same criteria and standards as applied previously by the Commission to

the Company's now-existing generating resources, and if found to meet those criteria and standards, will be afforded full cost-of-service treatment for so long as they are dedicated to the use of APS customers

- APS has the obligation and right to plan and provide resources as "provider of last resort" ("PLR") to all potential customers within its designated service area regardless of consumption or end-use unless and until specifically relieved of such obligation by order of the Commission, notwithstanding A.R.S. Section 40-202(B)(5), which purports to limit the Company's PLR responsibility to only those customers or potential customers using 100,000 kWh or less per year

- APS has the authority, without further Commission action, to join a regional transmission organization ("RTO") in conformance with FERC initiatives and the Commission's Electric Competition Rules

I addressed some of these issues in my Direct Testimony (Wheeler Direct Testimony at 22, *et seq.*) and again in an earlier part of this rebuttal, and although one Staff witness has acknowledged that "clarity" is needed on at least the first of these issues (Salgo Testimony at 12 and 25), that testimony does nothing to advance that "clarity," and another Staff witness appears to disagree with even the need for "clarity" (Jaress Testimony at 26, line 20 through 27, line 4). Indeed, the fact that Staff itself appears to have achieved no consensus on how APS should be planning to serve customers post-2006 is itself a compelling reason for the Commission to exercise its authority to clearly establish, or perhaps more accurately, restate fundamental regulatory policies in this critical area. The second issue is a corollary to the testimony of intervenors AECC and CNESE concerning "no stranded costs" and of CNESE's "core/non-core" proposal.

As stated, APS believes that it is currently responsible to serve customers in our service territory in a reliable and prudent manner. As part of this responsibility, the Company must plan for and acquire an appropriate portfolio of resources, which I believe should include both Company-owned power plants and wholesale purchases, as appropriate. We believe that wholesale purchases, along with renewables and demand-side management (concerning which there appears to be no issue with regard to at least the latter two as to either the Company's authority to engage in such activities or the ratemaking standards to be applied regarding those activities) can be an important part of the resource portfolio, but an over reliance on the market can unduly subject customers to the related risk of greatly fluctuating prices, insufficient supply, supplier default, or a combination of all three.

Q. WHY DO THESE ISSUES EVEN REQUIRE CLARIFICATION?

A. The reasons vary to some extent, although they all relate to this state's initial restructuring plan and then the "change in direction" triggered by Decision No. 65154. Consequently, I will address each issue separately.

A. Ability to Construct or Acquire New Utility-Owned Generation

Since initiating its "Generic Proceeding Concerning Electric Restructuring Issues" in early 2002 (Docket No. E-00000A-02-0051), the Commission has issued two orders, Decision No. 65154 and Decision No. 65743 (March 14, 2003), respectively referred to as the Track A and Track B Orders. These Decisions have dramatically altered the path of electric restructuring previously established in Arizona by the Commission's Electric Competition Rules and by the 1999 APS and Tucson Electric Power Company ("TEP") Settlements approved in Decision Nos. 61973 and 62103 (November 30, 1999). Under the Electric Competition Rules, APS was required to divest almost all of its existing generation and was forbidden from constructing new generation, excepting (in both instances) for small amounts related to the Environmental Portfolio Standard. All necessary approvals for such divestiture were granted by the Commission in its approval of the 1999 APS Settlement, wherein it found that divestiture was in the public interest. *See* Rule 1615 (A) and A.A.C. R14-2-1618; and also Decision Nos. 61973 and 63354. All future (post-2002) power requirements for APS and TEP were to come from the wholesale generation market.

The Track A Order prohibited divestiture by APS and TEP of "interests in any generating assets." Decision No. 65154 at 32. Thus, this Decision required APS to remain a vertically-integrated "traditional" electric utility. And in doing so, the Commission explained its actions by declaring:

> In retrospect, it was a good idea to delay divestiture and competitive procurement in the APS and TEP Settlement Agreements, given what has happened in the last two or so years, including the experience in California; the market volatility and illiquidity; and the lack of public confidence in the transition to electric deregulation and ability of regulators to prevent price spikes, ensure reliable service, and prevent bankruptcies. Even today, there is not agreement amongst economists, much less regulators, as to why and what happened in California, happened, and how to prevent a similar or related occurrence. [Decision No. 65154 at 22.]

In the same Decision, the Commission also "modified" Decision No. 62416 "which approved APS' Code of Conduct but also prohibited APS from providing competitive generation." *Id.* at 26-27. The Track A Order did not indicate precisely how it was "modifying" Decision No. 62416, but the clear inference was that the modification of the prior Decision was to allow APS to own and acquire generation that would be subject to traditional cost-of-service regulation. In compliance with the Track A Order, the Company filed a revised Code of Conduct on November 12, 2002.

Despite the above actions, and the Track A Order's pointed criticism of the wholesale power market, the Track A Order did not establish clear direction about how APS was to approach future generation resource needs. There was no specific mention about either the ability of APS to construct or acquire new generating plants or, perhaps more importantly, what would be the ratemaking treatment of such future resource additions. Instead, the Commission merely indicated that:

> ... we will require APS and TEP to acquire, at a minimum, any required power that cannot be produced from its own existing assets, through the competitive procurement process as developed in the Track B proceeding. The amount of power, the timing, and the form of procurement shall be determined in the Track B proceeding.
> [*Id.* at 23 (footnotes omitted).]

In the subsequent Track B Order, the steadily growing confusion over the future responsibility for meeting the reliability needs of customers and the Company's ability to prudently plan for and meet those needs other than through reliance on an unstable and unpredictable wholesale power market, became even more evident. The Commission required the Company to conduct a competitive solicitation both to satisfy its "unmet needs," as defined therein, and to seek economic alternatives to its existing "must-run" generation within transmission-constrained portions of the APS service area. Yet, at the same time, the Order indicated that: "[T]his Order is not intended to change the current rate base status of any such existing [generating] assets." Decision No. 65743 at 16. APS was further required to file with the Commission a so-called "secondary procurement protocol" to acquire purchased power needs that remain unmet by the initial Track B solicitation. *See* Decision No. 65743 at 77.

Neither the Track B process approved in Decision No. 65743 nor the Secondary Procurement Protocol required by such Decision provided a means of evaluating, let alone acquiring, long-term resource acquisitions. There was no mention in either the Track B Order, or the Staff Solicitation Process adopted by said Order and attached thereto as Exhibit A, of the option of building or buying a power plant and thereafter operating it for the benefit of APS customers under traditional cost-of-service principles.

The Track B Order further declined to provide for any Commission pre-approval of individual resource decisions by APS and TEP, or to reinstitute an integrated resource planning ("IRP") process approving on a more generic level, a utility's plan to meet its reliability obligations. Moreover, the Track B Order was silent even as to the <u>standards</u> for *post hoc* review by the Commission of such resource decisions in future rate proceedings.

As discussed previously, the Company is in the midst of efforts to secure additional long-term resources under the assumption that it remains responsible for planning and acquiring resources necessary to serve all existing and future customers within its service territory and has recently submitted a 10-Year Plan calling for over $1 billion in new high-voltage transmission infrastructure in part to support those resource acquisition efforts. Rate-basing of the PWEC generation, as is proposed in this rate case, is essential but does not solve the problem of procuring additional long-term resources, even though it certainly will reduce the potential severity of that problem, especially over the life of that generation. But including the PWEC generation, Mr. Davis' Rebuttal Testimony indicates a shortfall of over 1400 MW by 2007, which will grow to over 3000 MW by 2011. The Secondary Procurement Protocol was primarily designed for short-term resource acquisition, as was the original "Track B" process, and as stated above, neither process expressly provides for the evaluation of utility-owned generation under traditional utility cost-of-service principles.

APS and Staff appear to interpret the pre-Track A Commission pronouncements differently when it comes to new utility-owned generation, and when this is combined with the seemingly contradictory language in both the Track A and Track B Orders, language that focuses exclusively on purchased power solutions to the Company's growing resource needs, it is abundantly evident that some clarity and regulatory certainty needs to be brought to the areas of APS resource planning and resource acquisition. The Commission can do so by stating clearly and unambiguously that APS can and has the obligation to build or buy new utility-owned generating facilities if and when APS, in the exercise of prudent managerial judgment, reasonably believes, based on then-existing facts and circumstances, such construction or acquisition to be in the best long-term interests of its customers, not withstanding any language in the Track A and Track B Orders to the contrary.

Such a declaration of regulatory policy is not startling or revolutionary. It merely restores to APS the ability it had to make decisions to protect reliability that the Company enjoyed prior to the Electric Competition Rules. This is the same authority that most other electric utilities in America, including SRP, has today and one that APS has exercised with skill and prudence in the past. Given the stakes involved, the alternatives to establishing clear and consistent regulatory policies serve neither the Company and its customers nor this Commission, whether that alternative be a retreat by APS from utility asset-backed resource expansion (a move that Mr. Bhatti's analysis shows would greatly increase costs to our customers) or a need to individually bring every significant resource decision to the Commission for pre-approval of its eventual ratemaking treatment.

Q. HAS THE TESTIMONY OF STAFF AND INTERVENORS ADDRESSED THIS ISSUE?

A. No. As I alluded to earlier, Staff and most intervenors approached resource planning and acquisition only in a very limited and tangential way and, unfortunately, not with recommendations that will clarify these issues on a going forward basis. I am disappointed that insufficient attention was paid to the longer term challenges of how electricity will and should be provided to our customers, what obligations utilities such as APS will have, and the role of competitive markets.

Instead, Staff's and certain of the intervenors' analysis of the PWEC assets was dominated by short-term considerations – specifically the concern about the overstated benefits in 2005-2006 from the Track B PWEC/APS agreement – and relied on little more than speculation for the years after 2006. This seems in direct contradiction to the admonition of a unanimous Commission in the *ACC Policy Statement Regarding New Natural Gas Pipeline and Storage Costs* dated December 18, 2003, which resulted from the Commission's groundbreaking Gas Infrastructure NOI. Therein, it was stated that "Arizona utilities should plan for natural gas infrastructure needs on a long term basis, recognizing that <u>some decisions may not necessarily lead to the lowest cost in the short term</u>." *Id.* at 2 (emphasis supplied). RUCO, which at least conducted a life-cycle present value analysis, then proceeded to ignore the results of that analysis, which supported the

Company's rate base proposal, and instead allowed itself to get diverted by shorter-term factors such as when the "cross-over" point occurs for this or that PWEC asset. And AECC did not bother to look beyond the lower revenue requirements of the Track B contracts in 2005 and 2006 before concluding that the longer-term option of rate-basing the PWEC assets should be rejected.

The testimony of Staff and these intervenors seems to reflect a dangerous, and so far unjustified, faith that a competitive market already found by the Commission to be dysfunctional, a market which has to date responded poorly to the two competitive solicitations held by the Company and a market that is littered with players in financial distress, will nonetheless somehow provide adequate, reliable power supplies in 2007 (after the Track B contracts are expired) at prices and on terms and conditions better than that offered by the Company's PWEC rate-basing proposal. Faith may not demand proof, but this Commission should demand that there be more than just opinion and theory before rejecting the sweeping economic analyses presented in this proceeding demonstrating the long-term economics of rate-basing the PWEC assets.

Q. DID NOT RUCO WITNESS SCHLISSEL ADVOCATE INSITUTION OF AN IMMEDIATE IRP PROCESS TO DETERMINE FUTURE RESOURCE REQUIREMENTS FOR THE COMPANY AT THE EXPIRATION OF THE TRACK B AGREEMENTS?

A. Yes, and although APS disagrees with his specific recommendation in this regard, I can agree that IRP is one means to vet the kinds of resource planning, resource acquisition and ratemaking standards issues discussed both in my rebuttal and in my Direct Testimony. However, it historically has been a very inefficient and time-consuming process that did not result in the sort of clarity in either objectives or means that is necessary here. It is also a process explicitly rejected by the Commission in its Track B Order. *See* Decision No. 65743 at 47.

Q. PLEASE EXPLAIN.

A. APS went through two full IRP triennial cycles in 1989 and 1992. It submitted a third IRP filing in 1995, but there was never a hearing on that filing, as the Commission suspended IRP in Decision No. 60385 (August 29, 1997). The 1989 IRP proceeding was not finally complete until the issuance of Decision No. 57589 (October 29, 1991). The 1992 filing also took a significant period of time, not being concluded until the middle of 1994. *See* Decision No. 58643 (June 1, 1994). And neither of these proceedings involved construction or acquisition of a power plant or even the solicitation of a long-term PPA. Moreover, at the end of the process, all the Commission determined was whether the APS resource plan was or was not "consistent" in some unspecified manner with the resource plan advocated by Staff. There was no determination as to which plan or combination of plans was deemed prudent, let alone "least cost." There was certainly no "approval" given for any particular resource option. Thus, IRP, at least as it was practiced in this jurisdiction in the early 1990s, even if it could be concluded in a timely fashion, would not bring the requisite closure on the issues raised in this proceeding.

B. Ratemaking Standards and Criteria for New Utility-Owned Generation

Q. WHAT IS THIS ISSUE ALL ABOUT?

A. Although closely related to the previous issue, APS believes it equally important that all potential resource acquisitions be on a "level playing field" when it comes to their prospective ratemaking treatment. By raising this issue, it is not the Company's intent to ask for any sort of generic "pre-approval" of unspecified resource additions. Clearly, any such pre-approval should be limited to specific proposals, whether those proposals are new power plants or new long-term power agreements. However, it is important that the evaluative ratemaking criteria and standards to be applied to resource additions be understood in advance and that they not bias the resource decision itself.

In the Track A Order, Staff is quoted as recommending that "if a utility chooses to retain its [generating] assets, . . . the Commission should apply cost-of-service principles when setting rates." Decision No. 65154 at 11. Although the Commission itself did not appear to take issue with that recommendation, neither did it expressly adopt the Staff position, although Staff's recommendation was clearly consistent with Arizona law.

In the Track B Order, the Commission's language about preserving "the current rate base status of any such existing [generating] assets" (Decision No. 65743 at 16) gave a clearer indication that existing utility-owned generation would continue under traditional cost-of-service regulation and that the issue of plant retirement would be evaluated under traditional economic criteria rather than through environmentally-based mandates, but the Order was silent on the ratemaking regime that would be applied to future utility-owned generation. And the language used with regard to even purchase power agreements was vague and possibly contradictory:

> To the extent that the utilities need guidance as to the [rate] review of their procurement decisions, <u>among the issues</u> the Commission <u>may look to</u> are: (1) whether the process was fair and non-discriminatory, or whether it favored an affiliate; (2) evidence to support that the decision was in the best interests of ratepayers; and (3) whether the utility's decision facilitated the development of a competitive

> wholesale generation market in Arizona. [Decision No. 65743 at 65 (emphasis supplied.]

Because the short list of criteria given was expressly declared to be a non-exclusive list, with no firm commitment by the Commission to even consider the criteria that were listed, and there was no hierarchy established as to which criterion was considered by the Commission to be most important, which least important, how compliance would be measured or evaluated, and so on, the quoted language is, frankly, of limited value in making intelligent resource decisions and did nothing to clarify the uncertainty created by the Track A and Track B Orders.

Aside from the lack of establishing any priority among even complimentary evaluative criteria, there is no hint as to what to do if one or more of the listed criteria are not complimentary, as they quite likely will be in actual practice. For example, depending on what is meant by the phrase, "the development of a competitive wholesale market in Arizona" such a goal may not be synonymous with "best interests of ratepayers" or, in every instance, even compatible with such interests if that market's "development" requires customers to accept lower quality service and higher prices. And what if providing APS customers "with reliable power at the lowest costs" conflicts with acquiring power that has the least impact on "air quality and water issues," which were both considerations mentioned by the Track B Order? Decision No. 65743 at 81. The Commission's old IRP process, despite its flaws, at least provided a regulatory mechanism to address, if not resolve, often conflicting regulatory goals such as those identified in the Track B Order.

In the case of purchase power contracts, the federal "filed rate doctrine" provides limits to the state's ability to disallow cost recovery of otherwise prudently entered into power agreements, thus potentially limiting the harm caused by the lack of evaluative standards in the Track B Order. However, there is no comparable federal doctrine applicable to utility-owned power plants. This lack of certainty, not of the eventual regulatory result itself (rate base or no rate base, or rate base at less than full cost-of-service), but the regulatory standards by which the result will be evaluated, places the option of utility-owned generation at a very significant disadvantage compared to purchase power alternatives. To expect utilities to commit up front hundreds of millions of dollars of investor funds without a clear understanding of the "rules of the game" is to expect a degree of trust by investors that is simply not likely to be forthcoming in today's chaotic financial markets.

This Commission has spoken out in support of the need to encourage long-term planning and basic infrastructure investment. Its policies in the areas of power plant and transmission line siting and in the evaluation of transmission adequacy have supported those words with actions. The Commission is likewise taking needed steps to encourage gas storage and transportation options for gas users in Arizona. Indeed, those who view the quality of regulatory support only in terms of equity returns and accelerated capital recovery often overlook the equally important, if not more important, role played by regulatory policies that provide, on a timely basis, certainty as to the standards regulators will apply in determining those returns and the rate of capital recovery, and regulatory policies which allow management the flexibility to meet those standards in a cost-effective and timely manner.

The present request provides the Commission with a unique opportunity to reaffirm the ratemaking standards that have become well-understood and accepted by the utilities and utility investors for many decades and upon which they have invested many billions of dollars in Arizona infrastructure. This in no way limits the Commission's ability to formulate appropriately developed and prospectively-applied new criteria and standards to as of yet unmade resource decisions, whether those be environmental in nature or more linked to some measurement of competitive market impact. Indeed, the Track B Order expressly contemplates the potential development of "environmental risk management" and demand-side management policies that could be applied to future resource decisions. Decision No. 65743 at 78. However, until these or other explicit evaluative criteria and standards are developed and adopted by the Commission, APS should be able to make choices based on the traditional criteria that look to actual and anticipated <u>life-cycle</u> benefits for customers, both economically and from the standpoint of reliability (including reliability of fuel source), with the assurance that any new standards and criteria for rate base or cost-of-service recognition will not be thereafter applied retroactively.

C. PLR Responsibility and Future Stranded Costs

1. PLR Responsibility

Q. WHAT DO YOU MEAN BY "PLR"?

A. PLR, or "provider of last resort," means that APS has the obligation to provide fully-bundled electric service on demand and pursuant to the terms, conditions and prices set by this Commission, to anyone in its service area for which the Company has such PLR responsibility. Correspondingly, to have PLR obligations carries with it a corollary obligation to prudently plan sufficient resources to meet that PLR public service duty.

Q. DOESN'T APS HAVE A UNIVERSAL PLR OBLIGATION FOR ITS ENTIRE SERVICE AREA?

A. Well, that clearly has been the case in the past. And APS believes that nothing in the Electric Competition Rules was meant to abrogate its "responsibility to provide reliable and reasonably priced service to [its] customers." Decision No. 65154 at 31. This requires APS to "furnish and maintain such service, equipment and facilities as . . . will be in all respects adequate, efficient and reasonable." *Id.* at 31-32 (quoting from A.R.S. Section 40-361). And although APS agreed to the Commission's modification of its certificates of convenience and necessity ("CC&N") in Decision No. 61973 to the extent necessary to allow ESPs to provide Commission-designated "Competitive Electric Service," the Commission did not modify the Company's CC&N to eliminate the pre-existing requirement that APS serve or offer to serve all applicants for service within its service area at just and reasonable rates.

In HB 2663, which became the Arizona Electric Competition Act, there is no definition of the term PLR. However, using the curiously indirect language prevalent throughout that Act, A.R.S. Section 40-202 (B) states that:

> In order to transition to competition for electric generation service, the commission's authority is confirmed to:
>
> > 5. Require the electric distribution utility that is a public service corporation to act as the supplier of last resort for electric generation service for every retail electric customer within its electric distribution service territory whose annual usage is one hundred thousand kilowatt hours or less if

> other electricity suppliers are unwilling or unable to supply electric generation service and whose electric generation service has been discontinued through no fault of the retail electric customer.

Read literally, the provision could be construed as attempting to limit APS' PLR responsibility to only those customers using 100,000 kWh or less per year, and only to even these smaller customers under very specific circumstances. As such, it would not only conflict with the service obligation described above, but with that set forth in A.A.C. R14-2-1606 (A) ["Rule 1606 (A)"]:

> Until the Commission determines that competition has been substantially implemented for a particular class of consumers (residential, commercial industrial) so that <u>all</u> consumers in that class have an opportunity to participate in the competitive market, and until all Stranded Costs pertaining to that class of customers have been recovered, each Affected Utility <u>shall</u> make available to <u>all</u> the consumers in that class in its service area, as defined on the date indicated in R14-2-1602, Standard Offer bundled generation, transmission, ancillary, distribution, and other necessary services at regulated rates.[Emphasis supplied.]

Customers using more than 100,000 kWh per year accounted for some 36% of the Company's 2003 peak demand and 50% of annual energy sales. From a planning perspective, it is critical for APS to know whether it does or does not need to plan new resources to meet this significant customer demand in its service area. To not know risks either an unnecessary over-commitment by the Company to new resources that may well impose future costs on the Company's smaller customers, or alternatively, the possibility of crippling shortages and curtailments, with resultant loss of employment and general economic activity within much of Arizona. APS does not believe that the conditions stated in Rule 1606 for termination of the Standard Offer service option to any class of APS customer have been satisfied, or that it would be a particularly good idea to eliminate this option for these larger customers even if they had been. As was seen back in 1999-2000, ESPs can disappear as quickly as they arrive, especially when market conditions are bad. If there is no existing infrastructure investment by the incumbent utility to provide substitute service, APS customers may find themselves "high and dry" with few if any options to simply foundering on their own in what is then likely to be another chaotic power market.

D. APS Authority to Join an RTO

Q. RUCO WITNESS DR. RICHARD ROSEN SUGGESTS THAT APS NOT BE PERMITTED TO JOIN A FERC-APPROVED RTO. WHAT IS YOUR RESPONSE?

A. The Electric Competition Rules have long supported the concept of a regional transmission organization under FERC jurisdiction. Specifically, A.A.C. R14-2-1609 (C) states:

> The Commission supports the development of [a] Federal Energy Regulatory Commission-approved Regional Transmission Organization (RTO) . . . The Commission believes such organizations are necessary in order to provide non-discriminatory retail access and facilitate a robust and efficient electricity market.

Later, in subsection (F) of that same Rule, the Commission directs that:

> Each of the Affected Utilities shall make good faith efforts to develop a regional, multi-state Independent System Operator or Regional Transmission Organization.

In addition, Section 7.6 of the 1999 APS Settlement, which this Commission approved and adopted in Decision No. 61973, requires the Company to support and join an RTO.

APS has, in fact, made more than a good faith effort to develop this region's FERC-approved RTO, WestConnect, and has been a leader in attempting to form that entity and in securing its FERC approval. Lately, some long-time participants in WestConnect (e.g., Public Service Company of New Mexico) have received mixed signals from their state regulators concerning continued involvement in WestConnect, and there is the continued challenge of ensuring the essential participation of non-jurisdictional entities not directly subject to FERC's mandates. As an original founder of this RTO and as an Affected Utility acting pursuant to Commission direction and approval, APS believes it appropriate for the Commission to confirm that Rule 1609 and Decision No. 61973 already provide whatever Commission authorization is necessary for the Company to join and participate in WestConnect or other FERC-approved regional transmission organization so long as that participation does not vest any ownership interest in APS transmission facilities in WestConnect. This would permit APS to continue to take a leadership role in persuading other regional transmission owners, both public and investor-owned to "stay the course" with WestConnect or some similar RTO, should circumstances require modification or evolution of WestConnect as presently contemplated and organized.

1. Future Stranded Costs

Q. ARE PLR OBLIGATIONS AND THE POTENTIAL FOR STRANDED COSTS LINKED?

A. Absolutely. CNESE witness Fulmer recognizes this, and although APS disagrees with his proposed modification of our service obligation to certain customers, Mr. Fulmer is clearly addressing the right issue. Mr. Higgins, on the other hand, seems to want the security of an incumbent utility with a PLR obligation to his clients and the right to choose another energy supplier, but also at the same time to be free of even the potential for incurring future "stranded cost" responsibility. At this point, I need to refer the Commission to Section VIII of my Rebuttal Testimony wherein I discuss the futility of seeking to always have the best of both regulation and competition and about that being an unrealistic expectation, with the need to establish the appropriate trade-off between sometimes conflicting goals. Here is a perfect example.

Q. PLEASE EXPLAIN.

A. If APS has the obligation to secure resources for a customer that also has the ability to leave APS for another supplier, there will <u>always</u> be the possibility that this departure will leave APS with what are now unneeded resources, or with resources that have a lower level of utilization and thus higher per unit costs. Regulators can minimize the problem to some extent by requiring notice before a customer may leave for direct access or, as is suggested by CNESE, modifying the PLR responsibility for certain customers, but they cannot eliminate the potential for "stranded costs" unless they get rid of PLR obligations entirely with regard to energy supplies. As it is, there is no escaping the fact that when customers leave an incumbent utility, there is the potential for higher per customer costs for those who stay. One can either assess those costs on the departing customer through an "exit fee" or a "stranded cost" charge (or a combination of both) or charge the remaining customers more. There is no magic wand that can simply make the costs go away, and there is no basis for requiring utility investors to absorb costs they were legally-required to incur in satisfying the Company's PLR obligations.

VI. <u>THE 1999 APS SETTLEMENT</u>

Q. HAVE APS AND ITS AFFILIATES BEEN HARMED BY THE FAILURE TO RECEIVE THE ITEMS BARGAINED FOR IN THE 1999 SETTLEMENT?

A. Yes. I find it astonishing that some would say we have not, or more surprising, that APS has actually come out better than it could have anticipated under the 1999 APS Settlement. (Jaress Testimony at 7, Smith Testimony at 12, Diaz Cortez Testimony at 18, and Higgins Testimony at 17.)

Q. HOW HAVE APS AND ITS AFFILIATES BEEN HARMED?

A. Let me first recount again the tally of what APS gave up and what it and its affiliates were to receive.

On the "give up" side of the ledger, we have:

- over $400 million in rate decreases through June of 2004
- a moratorium on rate increases through June of 2004
- a $234 million write-off of costs the Commission had already determined the Company could fully recover
- the loss of 1/3 of divestiture-related costs, even though those also would have been fully recoverable under a previous (to the Settlement) Commission order
- the surrender without a fight (and without compensation) of its exclusive CC&N to provide what were now deemed as "competitive electric services"
- the dismissal with prejudice of what has to date proven successful litigation (by others not so bound) against the Electric Competition Rules, including the very Commission Rule that compelled divestiture in the first instance

On the "get" side, APS or its affiliates were to receive:

- the ability to divest its existing generation to an affiliate or affiliates, which divestiture in turn became the basis for an entire business plan
- certainty as to amount of potential "stranded cost" recovery it would receive under varying assumptions as to the scope and timing of customer loss to direct access

- the ability to timely recover from (or pass along to) its customers higher (or lower) power supply costs after June 30, 2004 through a rate adjustment mechanism

- the waiver of substantive affiliate rule restrictions on transactions by and between non-APS entities in the Pinnacle West group

- the waiver of certain non-substantive affiliate reporting requirements on the part of APS

- the rescission or amendment of certain prior individual Commission reporting orders that were either duplicative of others or had already been mooted by subsequent events

- the promise of a Staff investigation into whether some statutory requirements for public service corporations should be waived as to competitive services provided either by APS or its affiliates pursuant to the authority granted the Commission in the Electric Competition Act

- a commitment that any regulation by the Commission of PWEC would not differentiate between PWEC and other merchant generators based on PWEC's affiliation with APS

The first, fourth and fifth "gets" have subsequently either been denied or revoked. *See* Decision Nos. 65154 and 65796. The sixth "get" was non-monetary in nature and reduced the reporting burden on the Commission as much as the Company. The third "get" was only partially granted even in principle, and both Staff and RUCO would take that away before APS had received so much as a nickel of cost recovery under its provisions. The second of these "gets" ended up garnering the Company all of $ 1 million. The seventh, an investigation to determine whether statutory waivers were appropriate, has never taken place in the four plus years since approval and adoption by the Commission of the 1999 APS Settlement. The eighth and last "get" is belied by the numerous restrictions placed on PWEC under Track B, and as a result of the Track A and financing orders. It's little wonder that APS believes it and its affiliates have been treated unfairly.

Q. STAFF WITNESS SMITH TESTIFIED THAT AT LEAST SOME OF THE RATE DECREASES CALLED FOR IN THE SETTLEMENT WOULD HAVE HAPPENED ANYWAY (SMITH TESTIMONY AT 8). WHAT IS YOUR RESPONSE?

A. That's speculation of the highest order and not supported by any revenue requirements analysis, either contemporaneous to the Settlement or as part of Ms. Smith's testimony. There was no rate case then pending, and both this proceeding and the one litigated case before this one (Docket No. U-01345-90-007, *et al.*), the latter of which lasted nearly two years, not including the time it took to put together the rate filing to begin with, show them to be massively time-consuming undertakings even under the best of circumstances. Moreover, in its appellate brief defending the 1999 APS Settlement, the Commission characterized the Company's rate reductions as "voluntary" and argued that APS may voluntarily agree to "forego revenue <u>to which it would otherwise be entitled</u>." Commission Response to Opening Brief of Arizona Consumers' Counsel at 19, *Arizona Consumers' Counsel v. Arizona Corporation Commission*, 1 CA CC 99-0006 (January 5, 2000). And even assuming Ms. Smith were correct and that at least part or perhaps all of the additional first year's rate decrease called for by the 1999 APS Settlement could have been eventually forced upon the Company in the absence of such Settlement, as you can see from my earlier response, the regulatory lag in implementing this hypothetical additional one-time decrease would itself have been many times more valuable to the Company than the minimal benefits APS has received to date from the 1999 APS Settlement. Under such a scenario, APS would not have taken any write-off, would still have its competition-related causes of action, all of its divestiture-related costs would clearly be recoverable under pre-1999 APS Settlement Commission decisions, and the likelihood of the Company being brought in annually for rate decreases in 2000, 2001, 2002 and 2003 exceedingly small given the time and effort such a yearly process would entail.

Q. DID NOT APS REPORT EQUITY RETURNS ABOVE THE 11.25% IMPLICIT IN THE 1999 SETTLEMENT IN 2000 AND 2001 AS MS. SMITH CLAIMS AT PAGE 10 OF HER TESTIMONY?

A. Yes, but she fails to note that APS reported equity returns below that level in 1999, 2002 and 2003. And it will again in 2004. Moreover, even the 2000 and 2001 results were skewed upward by the accounting treatment of the $234 million write-off (both by reducing the equity upon which a percentage return was calculated and by reducing the annual amortization of regulatory assets to reflect the earlier write-off) , unregulated marketing and trading profits not related to APS generation or to the provision of retail electric service, and the abnormally high market prices for the Company's excess energy, especially in the West. When these extra-ordinary or non-jurisdictional effects are removed, the Company's ROE for the two years cited by Ms. Smith falls to 12.3% and 8.1%, respectively and an average of 9.5% for the entire period 1999 through 2003. Based on the Company's average common equity during that same period, the difference between the 9.5% earned from regulated retail operations and the 11.25% ROE implicit in the 1999 APS Settlement translates into a cumulative under-earnings of $195 million.

Q. MS. SMITH ALSO TESTIFIED THAT THE $234 MILLION WRITE-OFF HAD NOT IMPACTED THE COMPANY'S "GOING FORWARD" COST OF SERVICE" (SMITH TESTIMONY AT 2). DO YOU AGREE?

A. That is neither an accurate nor relevant conclusion. The write-off resulted in a real and demonstrable loss of shareholders' equity, thus making the

Company more leveraged than would otherwise have been the case. The loss of any prospective return of or on that foregone equity is certainly significant to shareholders if not to Ms. Smith. And even if true, it would be irrelevant because what APS seeks is partial restitution for the failure to receive any of the substantial benefits it negotiated in the Settlement. If someone empties your bank account, the fact that he or she does not also garnish your future wages does not mean you have not been harmed and are not entitled to fair compensation for the loss.

Q. MS. SMITH FURTHER INDICATES THAT THE FAILURE TO HONOR THE PROMISE OF DIVESITURE DID NOT RESULT IN "SIGNIFICANT" HARM TO APS (SMITH TESTIMONY AT 2). DO YOU AGREE?

A. No. The APS general corporate credit rating was already dropped once in response to the Track A Order. That Order led directly to the Track B Order, which may have cost APS between 27% and 45% in higher prices for purchased power due to the delay in acquiring that portion of APS' needs for 2003-2006. Moreover, as much as Ms. Smith would like to ignore the impact on APS' affiliates, I cannot. Mr. Bhatti's evaluation of the market worth of the APS assets shows that PWEC would be more than viable during even the early years of the new PWEC assets' operation if divestiture had taken place. Mr. Davis testifies in his rebuttal that even under the original assumptions made at the time of the 1999 Settlement, it was the combination of the anticipated below-market costs of the non-Palo Verde APS generation plus the ability of the Palo Verde generation to generate positive cash flows that were to get PWEC through the first few years of its operation and allow it to achieve an investment-grade credit rating.

Q. DID THE TWO FINANCING ORDERS REFERENCED IN MR. JARESS AND STAFF'S SEEMING WILLINGNESS TO ALLOW ALL OF THE COMPANY'S DIVESTITURE-RELATED COSTS IN RATES COMPENSATE APS FOR THE REVERSAL OF COURSE ON DIVESTITURE?

A. Far from it, although we certainly needed both of the financing approvals and are thankful that Staff and the Commission agreed. But, these approvals provided only temporary relief from the predicament caused by the Track A Order and actually added to the damages incurred by the Company and its affiliates associated with that policy reversal.

Q. HOW CAN THAT BE?

A. The first financing order provided Pinnacle West with a backup credit line that will expire before rates become effective in this case. The second of the financing orders resulted in: (1) a lower return to APS and a lower revenue requirement in this proceeding (substantially lower under the recommendations of Staff and intervenors) because of the additional debt APS needed to incur in anticipation of receiving the PWEC assets; (2) the loss of the affiliate rule waivers granted under the Settlement; (3) the imposition of new affiliate restrictions (concerning the acquisition or disposition of property by non-APS affiliates Pinnacle West and PWEC) that did not exist even prior to the Settlement (4) the loss of additional millions to PWEC every year in the form of the interest premium paid to APS customers; (5) the imposition of a dividend limitation that may be triggered by adoption of Staff's recommendation in this case; and (6) the opportunity to have its integrity questioned in the "preliminary inquiry." APS sought the latter financing and agreed to these conditions simply because there was no other way to survive until this rate case gave the Commission its opportunity to address the aftermath of the Track A Order.

How these compensate either APS or its affiliates for anything is neither self-evident nor explained by Staff. And as to the "additional" one-third of divestiture costs, I note that net of Staff's disallowance of divestiture-related costs, a disallowance supported by not even an allegation of imprudence, APS is back to recovering only <u>60</u>% of the total divestiture-related cost it incurred in reliance upon the 1999 APS Settlement–<u>a percentage even lower than the 67% called for in Decision No. 61973</u>.

Q. DO EITHER MS. SMITH OR MS. JARESS ADDRESS THE OTHER HARMS SUFFERED BY APS RELATIVE TO THE 1999 SETTLEMENT <u>SINCE</u> THE TRACK A DECISION?

A. No. They ignore Staff's own recommendation that APS be denied a power supply adjustment mechanism. If adopted, APS has the very real potential for millions of dollars per year of additional losses, as is discussed in the Rebuttal Testimonies of Mr. Robinson and Mr. Ewen. They also ignore the affiliate restrictions re-imposed and the new restrictions imposed by the aforementioned financing orders and the reduced APS revenue requirement also attributable to such orders.

Q. BOTH MS. SMITH AND AECC WITNESS HIGGINS SUGGEST THAT THE LEVEL OF POTENTIALLY STRANDED COSTS FOUND IN THE 1999 SETTLEMENT AND DECISION NO. 61973 MAY HAVE BEEN TOO HIGH (SMITH TESTIMONY AT 14-18 AND HIGGINS TESTIMONY AT 12). DO YOU AGREE?

A. Too high compared to what? If the question is whether the $533 million figure referenced in the Settlement (which was the result of an analysis conducted by APS in 1998) was higher than a comparable and contemporaneous analysis looking at a longer period as suggested by Ms. Smith (Smith Testimony at 15-17), the answer is "yes and no." The level of stranded costs then calculated by the Company increased over some longer periods and decreased slightly over others. If the question is whether an analysis today, knowing what we know happened to market prices (up in 2000 and most of 2001, and depressed ever since), would have produced a different number (higher or lower), the answer is "yes," but both that fact and the recalculated number itself would be irrelevant to this proceeding. I do, however, agree with Mr. Higgins testimony (Higgins Testimony at 13) that assuming the parties to the 1999 APS Settlement would have agreed to allow APS the opportunity to collect the same $350 million in potentially stranded costs, even if APS had demonstrated a smaller total "stranded cost" figure, say $400 million, APS would have experienced a smaller write-off under the 1999 APS Settlement if its original calculation of potentially "stranded costs" had been lower. However, that is a questionable assumption given my recollection of the actual negotiations involved in the 1999 APS Settlement and also irrelevant given that APS did write-off the $234 million ($183 million in present value, or $533 million less $350 million).

Q. WHY DO YOU SAY THAT AN AFTER-THE-FACT CALCULATION OF THE LEVEL OF THE COMPANY'S POTENTIALLY STRANDED COSTS IS IRRELEVANT?

A. Because whatever they were anticipated to be then or are recalculated to be now, they were only potentially stranded in either case. In other words, if customers did not leave for direct access, there would have been no "stranded costs" irrespective of what they potentially could have been or how they were calculated. As we all know, no more than a handful of APS customers chose direct access and those that did quickly returned.

In an earlier answer, I indicated that APS has only actually collected $ 1 million in "stranded cost" charges to date. If the Commission had allowed a smaller "stranded cost" recovery, whether because the Company had asked for less or as a result of APS deciding to litigate the matter rather than settling, that figure would be even lower. APS is collecting no "stranded costs" today and can not even potentially collect any more after the end of this year. Thus, even if the Commission had found back in 1999 that the Company had "zero" potentially "stranded costs," there would have been little if any impact on the actual level of "stranded costs" incurred by APS. And such impact would not have triggered a write-off in any event, but rather would have caused a *de minimis* impact on annual earnings during 1999 and 2000, the only two years in which the Company had any direct access customers.

Q. ARE YOU SAYING THAT BUT FOR THE SETTLEMENT, APS WOULD NOT HAVE INCURRED ANY WRITE-OFF?

A. I am saying exactly that. Thus, the present circumstances are even more ironic that posited by Mr. Higgins when he speculates that if APS had sought a smaller level of potentially "stranded costs" it would have had a smaller write-off. In fact, if APS had simply refused to settle at all on the "stranded cost" issue and instead fully litigated the matter before the Commission, it would not have suffered a write-off irrespective of the outcome of such litigation.

VII. THE PRELIMINARY INQUIRY

Q. ARE YOU THE COMPANY'S PRIMARY WITNESS ON THE "PRELIMINARY INQUIRY" ORDERED BY DECISION NO. 65796?

A. No. Mr. Jack Davis also discusses the major conclusions of Mr. Jaress, while APS witnesses Ed Fox and Mr. Robinson address the more narrow issues of environmental permitting and general inter-affiliate accounting requirements.

Q. WHAT ADDITIONAL INFORMATION AND PERSPECTIVE CAN YOU PROVIDE THE COMMISSION ON THIS SUBJECT?

A. Ms. Jaress concludes, among other things, that various alleged actions by APS, Pinnacle West and/or PWEC have violated "the spirit, if not the letter" of the Company's Commission-approved Code of Conduct and certain provisions of the 1999 APS Settlement Agreement (Jaress Testimony at 11). I was intimately involved in both the 1999 Settlement proceeding and the subsequent proceeding that resulted in the Code of Conduct approved by the Commission in Decision No. 62416 (April 3, 2000). None of the actions discussed by Ms. Jaress in her testimony, even if they had taken place (and as discussed by Mr. Davis, some did not), remotely could be construed as violations of either our Code of Conduct or the Settlement. Indeed, they would have been specifically <u>authorized</u> by these documents.

Q. PLEASE DESCRIBE THE ORIGINS OF THE EXISTING APS CODE OF CONDUCT?

A. When I and Ms. Jaress use that term, we are talking about the Code of Conduct approved by this Commission in Decision No. 62416. The Company also has a Code of Conduct that has been approved by FERC, although APS and its affiliates have received waivers of large segments of this latter Code. FERC also has Standards of Conduct, which primarily relate to the required functional separation of APS' transmission business from the generation marketing business of APS and its affiliates.

The Commission-approved APS Code of Conduct was the product of both A.A.C. R14-2-1616 ("Rule 1616") and Section 7.7 of the 1999 Settlement. Decision No. 61973 (October 5, 1999), which approved the Settlement, required APS to submit a proposed Code of Conduct within thirty days. On

October 28, 1999, APS filed the required Code of Conduct proposal. After receiving comments from Staff and interested parties, APS filed a revised proposal on January 5, 2000. This revised Company proposal was followed on January 12, 2000 by the filing with the Commission of a series of nine "Policies and Procedures" designed to implement specific provisions of the Company's proposed Code and to address each of the nine subject areas covered by the Code, as specified by the Commission in Rule 1616.

Q. DID THE COMMISSION ADOPT THE REVISED APS-PROPOSED CODE OF CONDUCT?

A. No. Staff filed an alternative Code of Conduct on January 18, 2000. With some minor changes, the Company agreed with the Staff-written Code of Conduct and a Stipulation to that effect was submitted on February 22, 2000. The Commission adopted the Joint [APS and Staff] Proposed Code on Conduct in Decision No. 62416. The implementing Policies and Procedures were revised to be consistent with the now Commission-approved Code of Conduct and were filed with the Commission on June 2, 2000.

Q. DID THE CODE OF CONDUCT COVER EITHER PINNACLE WEST OR PWEC?

A. No. As delineated in Rule 1616, the Code governed only the interaction of APS and what the Code defined as its "Competitive Electric Affiliates." That latter term is expressly limited in Section I of the Code to Electric Service Providers ("ESP"). An ESP, in turn, is defined in A.A.C. R14-2-1601 as "a company supplying, marketing, or brokering <u>at retail</u> any Competitive Services pursuant to a Certificate of Convenience and Necessity [emphasis supplied]." Neither Pinnacle West nor PWEC has ever provided or offered to provide any services, competitive or otherwise, "at retail," and neither has a Certificate of Convenience and Necessity. Thus, the Company's only "Competitive Electric Affiliate" was and is APS Energy Services Company, Inc. ("APSES"). There were provisions in the Code addressing circumstances in which Pinnacle West either provided common services to both APS and APSES or had officers/directors common to both APS and APSES, none of which circumstances are relevant to the "Preliminary Inquiry."

Q. DOES MS. JARESS ALLEGE ANY EVEN ARGUABLY IMPROPER DEALINGS BETWEEN APS AND APSES?

A. No. Transactions or other dealings between APS and APSES are not even mentioned in her testimony.

Q. HAD THE APS CODE OF CONDUCT DEFINED "COMPETITIVE ELECTRIC AFFILIATE" IN A MANNER THAT WOULD HAVE ENCOMPASSED EITHER PINNACLE WEST OR PWEC, ARE THERE TRANSACTION BETWEEN APS AND THOSE ENTITIES THAT WOULD HAVE VIOLATED THE CODE?

A. No. Indeed the only two transactions discussed in Ms. Jaress' testimony that would have been addressed by this hypothetically-expanded Code of Conduct would be: (1) the power sales agreement between Pinnacle West Marketing & Trading and APS; and (2) the transfer of land at the Company's West Phoenix and Saguaro station sites from APS to PWEC.

Q. HOW WOULD SUCH TRANSACTIONS HAVE BEEN HANDLED UNDER THE CODE OF CONDUCT HAD THEY TAKEN PLACE BETWEEN APS AND APSES?

A. The answer is found in Section VIII (B) of the Code, which in turn references the reader to Code of Conduct Policy and Procedure No. 1– Affiliate Accounting Policies. Under Section V (B) of such Policy, power sales from a "Competitive Electric Affiliate" to APS are to be "at a price not to exceed market price." Since Mr. Davis testifies in his rebuttal that the draft M&T/APS power contract referred to in Ms. Jaress' testimony calls for precisely that measure of inter-affiliate pricing, it would have been fully consistent with the "spirit and letter" of the Company's Code of Conduct, if that Code of Conduct had governed such a transaction.

As to the land transfers, it would have been addressed by Section VIII (D) of Policy and Procedure No. 1. Specifically, that Section states: "[T]ransfers of assets include transfers of tangible real or depreciable personal property and intangible property used in a trade or business." Land is obviously tangible real property. Section VIII (D) goes on to require that "[T]ransfers of assets and liabilities between APS and its Competitive Electric Affiliate will be at net book value as of the date of the transfer . . . [emphasis supplied]." Thus, had PWEC been subject to the Code, the transfer of APS land at West Phoenix and Saguaro would have satisfied both the "spirit and letter" of that Code. Moreover, as I discuss below, this transfer of generation-related assets at book value would have been authorized by the 1999 Settlement and Arizona law independent of the provisions in the Commission-approved APS Code of Conduct.

Q. WOULD THE CODE OF CONDUCT, IF APPLICABLE, HAVE REQUIRED EITHER OR BOTH OF THESE TRANSACTIONS TO BE "ARMS LENGTH"?

A. No. The term "arms length" is found nowhere in either the Code of Conduct itself or in Rule 1616. This is not surprising. I suspect that the very reason why regulators, in some instances, impose specific affiliate transaction pricing guidelines such as are contained in Policy and Procedure No. 1, or require prior regulatory approval of affiliate transactions in other instances (e.g., A.A.C. R14-2-804), is because the process of "arms length" negotiations (as contrasted to an "arms length" result) can be more difficult between affiliates in the real world. Thus, the emphasis of affiliate transaction regulation is necessarily and properly focused on results and impact rather than form and process.

Q. WOULD THE 1999 APS SETTLEMENT HAVE PROHIBITED EITHER OR BOTH OF THE TWO TRANSACTIONS DISCUSSED ABOVE?

A. No. In fact, both were authorized by the 1999 APS Settlement.

Q. HOW IS THAT?

A. Ms. Jaress herself acknowledges that the Settlement allowed APS to purchase power from an affiliate, whether it is Pinnacle West or PWEC. (Jaress Testimony at 18.) However, she does not note that the Commission also specifically found in Section 4.4 of the Settlement that:

> APS will purchase any electric energy from its EWG affiliate at market-based rates. The Commission has determined that (1) the proposed transaction [power sales to APS] will benefit consumers and not violate Arizona law; (2) the proposed transaction will not provide APS' EWG affiliate an unfair competitive advantage by virtue of its affiliation with APS; (3) the proposed transaction is in the public interest. [Emphasis supplied.]

Thus, the draft Pinnacle West Marketing & Trading agreement with APS, which was based on market prices pursuant to Pinnacle West's market-based FERC tariff, was exactly what was envisioned by the Settlement. And the Settlement did more than simply permit such transactions, it found them to "benefit consumers," to be "in the public interest," and not to provide the Company's affiliate with an "unfair competitive advantage."

As to the land transfer, Section 4.1 of the Settlement specifically authorized APS generation assets to be transferred to PWEC "at book value," and Exhibit C to the Settlement clearly identified West Phoenix and "associated land" as being among the competitive generation assets to be transferred to PWEC. Moreover, to the extent that the land was surplus, it could have been transferred at the Company's discretion under A.R.S. Section 40-285 (C) independent of either the Settlement or the APS Code of Conduct.

Q. ALTHOUGH NOT EXACTLY A "TRANSACTION," MS. JARESS APPEARS TO BE CRITICAL OF THE JOINT RESOURCE PLANNING FUNCTION EXERCISED FIRST BY APS AND THEN BY PWEC (JARESS TESTIONY AT 19, LINE 16 – 20, LINE AND ALSO AT 29, LINES 15-17). WOULD SUCH JOINT PLANNING HAVE GIVEN PWEC "AN UNFAIR COMPETITIVE ADVANTAGE" OR WAS SUCH PLANNING PROHIBITED BY ANY COMMISSION ORDER OR REGULATION?

A. No, although to some competitors, any advantage another competitor has, or is believed to have, may seem "unfair," just as "constructive" criticism often seems less "constructive" when you are the recipient. One must remember, however, that up until the entry of the Track A Order, APS generation and PWEC generation were to be part of a single entity – PWEC. Not only was joint resource planning <u>not</u> prohibited by any Commission order or regulation, such planning would strike me as being so obviously logical and prudent under the then-existing circumstances that I do not understand Ms. Jaress' concern. To the extent PWEC gained any "advantage" from the Company's decades of experience in resource planning, construction and acquisition, there was certainly nothing "unfair," let alone unlawful about it, and such "advantage" was the direct result of the Commission's own divestiture policy rather than any improper anti-competitive activity by APS and PWEC.

Q. COULD APS HAVE CONSTRUCTED OR ACQUIRED AN INTEREST IN NEW GENERATION AFTER 1999 AND PRIOR TO 2003?

A. No, although I do not know what this issue has to do with the "Preliminary Inquiry" unless APS' strict adherence to the "spirit" and "letter" of its Code of Conduct and Rule 1615 (A) is itself somehow believed improper by Staff. However, the answer to this question is significant for another reason, which I explain later in this portion of my Rebuttal Testimony.

Q. MR. JARESS APPEARS TO DISPUTE THIS CONCLUSION (JARESS TESTIMONY AT 26, LINE 20 THROUGH 27, LINE 7). WOULD YOU RESPOND?

A. Of course, and I must add that not only is this the first time a Staff witness has disputed the Company's interpretation of A.A.C. R14-2-1615 (A) ["Rule 1615 (A)"] and the APS Code of Conduct's definition of "Interim Competitive Services," but Ms. Jaress seems to be at odds with Mr. Salgo, who asks the Commission for "clarity" of the issue of utility-owned generation (Salgo Testimony at 12 and 25). I find Mr. Jaress' position especially ironic in that both Rule 1615 (A) and the specific provision of the APS Code of Conduct in question (Section X) were proposed by Staff in the first instance. In any event, Ms. Jaress' testimony does not provide any analysis of the provisions in question to justify her opinion, which is also inconsistent with at least two prior Commission decisions and a previous Staff Report on the APS Code of Conduct.

Q. PLEASE CONTINUE.

A. I will begin with Decision No. 63354 (February 8, 2001). This Decision granted APS "a waiver of R14-2-1615 (A) [Rule 1615 (A)] as needed to allow the applicant [APS] to own 'solar resources' and 'environmentally-friendly' renewable electricity technologies . . ." (Decision No. 63354 at 4.) Why would APS need a waiver of Rule 1615 (A) to own, build and buy renewable generation resources if it were not otherwise prohibited from such actions? And interestingly, APS did not even request the granted waiver, since the application referenced in the quote only sought approval of the Environmental Portfolio Standard Surcharge. The waiver was granted by the Commission on its own at the recommendation of Staff.

In Decision No. 65154 (the Track A Order), the Commission indicated that its decision "modified," among other prior orders, Decision No. 62416 "which approved APS' Code of Conduct <u>but also prohibited APS from providing competitive generation</u> [emphasis supplied]." Decision No. 65154 at 26-27. Why would Decision No. 65154 need to modify the APS Code of Conduct in this regard if APS were not otherwise prohibited from constructing or acquiring new generation? And lest there be any confusion that the term "competitive generation" might be referring to something less than all of the Company's generation, I would cite the Commission's Concise Explanatory Statement ("CES"), as appended to Decision No. 61969 (September 29, 1999). Decision No. 61969 approved the present version of Rule 1615 (A). The CES states that it is "clear that competitive generation includes all generation." Decision No. 61969, Appendix B at 60.

Finally, APS submitted Code of Conduct revisions on November 12, 2002 in compliance with Decision No. 65154. These revisions included, among other changes, removing the language alluded to in Decision No. 65154, which language APS argued limited it from acquiring new generation prior to divestiture. On August 13, 2003, Staff filed a Report endorsing these specific changes.

I wholeheartedly agree with Mr. Davis' Rebuttal Testimony in that it would have been inconsistent, to say the least, with the Commission's whole divestiture plan for APS to have invested hundreds of millions of its dollars in new generation that would then have to be divested within months of its completion (or in the case of West Phoenix CC-5, prior to its completion). And it would have been downright foolish to ask our customers to pay the literally millions it might have taken to effectuate such a "turnaround" divestiture. But this Commission needs to know that this prohibition on new APS generation, like the requirement that APS divest, was not just a figment of our imagination, and that the construction of these PWEC assets by an entity other than APS along with the subsequent financial ramifications are the direct result of Commission actions – actions that APS is asking be addressed in this proceeding.

VIII. RETAIL COMPETITION AND TRANSMISSION ACCESS

A. Retail Competition

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF MR. FULMER, A WITNESS FOR CNESE?

A. Yes, I have.

Q. DO YOU DISAGREE WITH SOME OF HIS ASSERTIONS AND RECOMMENDATIONS?

A. Yes. Mr. Fulmer has made several assertions about APS' general attitude towards retail competition and the potential impacts from the Application that are inaccurate. Mr. Fulmer also makes assertions about the "success" of retail access in other jurisdictions that warrant close examination by this Commission in the appropriate forum, which I contend is in Docket No. E-00000A-0200051. In addition, CNESE has made several specific recommendations for this proceeding concerning both the availability of Standard Offer Service and the need for additional oversight of the

Company's transmission open access obligations under FERC. Neither recommendation should be adopted at this time.

Q. WHY NOT?

A. First of all, I believe that CNESE has mischaracterized the Company's general attitude toward retail competition in its service territory (Fulmer Testimony at 13). As far back as in its December 4, 1995 settlement with Staff, which the Commission approved in Decision No. 59601 (April 24, 1996), APS has taken a leadership position in focusing the restructuring debate on the truly central issues affecting incumbent utilities, competitive market entrants, and customers. Attachment 9 to that settlement – "APS Position on Issues Raised by Industry Restructuring" – is attached as Schedule SMW-2RB. And we did more than just talk about competition. The Company has spent considerable effort and expense developing and implementing the various systems, processes, rates, and other elements necessary to implement retail competition. It also was the first Affected Utility to agree to open its service area to retail competitors and the only Affected Utility to actually have greater than a token one or two customers select direct access.

In addition, CNESE makes non-specific and unsubstantiated assertions that APS' proposed rates are anti-competitive. Mr. Fulmer states (Fulmer Testimony at 29, lines 14 – 16) that "APS should not set rates for commercial and industrial customers in a predatory fashion such as through cost-shifting or special contract rates, so as to effectively prevent potential competitors from entering the market." This negative inference (that APS rate proposals represent cost shifting or special deals to thwart retail competitors) is neither accurate nor supported by even a single example. As testified by the Company's rate design expert, Alan Propper, APS' proposed rates are unbundled in a manner that reasonably reflects component costs and provides appropriate information and price signals to allow retail competition to succeed or fail on its own merits. More importantly, other parties to this proceeding that could be impacted by this issue, including Staff and AECC, have been generally supportive of APS' proposed unbundling of Standard Offer rates.

Interestingly enough, Staff's and RUCO's recommendations for significant rate reductions, with APS customers thereafter also insulated from accurate price signals resulting from volatile fuel and purchased power costs, will harm CNESE's interests far more severely than anything APS is imagined by Mr. Fulmer to have done in designing its proposed rates. I am sure that Mr. Fulmer would agree that setting artificially low Standard Offer rates is <u>the</u> most anti-competitive action this Commission could take.

Finally, CNESE has mischaracterized the Company's support for and involvement in the Commission's current review of the Electric Competition Rules (Fulmer Testimony at 25). APS has participated in this review and has offered constructive comments on important issues that need to be resolved in order to evaluate the costs and benefits and to establish the ultimate goals of retail electric competition in Arizona. CNESE has characterized these comments as "unreasonably critical." However, I believe that such characterization is inaccurate and unfair. Without re-debating all the competition issues in this proceeding, I will simply point out that some of these unresolved issues raised by APS are central to a reasoned discussion of the goals and impacts of retail access and are themselves raised by CNESE in making one of its primary recommendations.

Q. COULD YOU EXPLAIN HOW THOSE APS ISSUES TO WHICH YOU JUST ALLUDED ARE RELATED TO MR. FULMER'S TESTIMONY?

A. Yes. For example, one of the important issues that we believe needs to be resolved is who is ultimately responsible for ensuring electric supply to end users and what means are permissible in meeting that obligation. I have explained their importance at some length in my Direct and Rebuttal Testimonies. Mr. Fulmer has, in this docket, argued that the Commission should implement a "core/non-core" strategy where customers with aggregated loads greater than 250 kW would have a Standard Offer Service provided largely, if not exclusively, through what CNESE describes as "shorter-term market resources."

Q. WHAT IS YOUR CONCERN WITH THIS PROPOSAL?

A. In the first instance, the Company does not agree that some of its customers are either more important than others or somehow less deserving of protection from an unstable short-term energy market. And even Mr. Fulmer appears to acknowledge that the "core/non-core" distinction would require an express modification of the Company's traditional obligation to serve and that his proposal could subject commercial and industrial customers that wish to remain on Standard Offer service to additional risk from the volatility of short-term wholesale market prices. Whether or not this risk is offset by other perceived benefits is ultimately a decision that should be made by the Commission with input from all affected parties, specifically from Mr. Higgins' clients, and in the context of other important issues concerning retail competition. In my previous discussion of PLR, I noted that the Commission had already established criteria by which to judge whether Standard Offer service should be withdrawn from particular classes or subclasses of customers. *See* Rule 1606 (A). I believe that at a minimum, the Commission should make similar findings before consideration of proposals to water down Standard Offer service into "Standard Offer – Lite" for those customers deemed by the Commission to be "non-core."

Q. DO YOU DISAGREE WITH OTHER RECOMMENDATIONS MADE BY CNESE?

A. Yes. In addition to the "core/non-core" issue, Mr. Fulmer also recommends that the issue of any potential future stranded costs should be determined in this proceeding (Fulmer Testimony at 17). This is similar to Mr. Higgins' recommendation (Higgins Testimony at 25), although unlike Mr. Higgins, Mr. Fulmer makes the essential connection between the nature of any continued obligation to serve and the potential for future stranded costs so long as retail access is permitted. I address both these issues (obligation to serve and its relation to the potential for future "stranded costs") in an earlier Section of my Rebuttal Testimony.

Q. HAS RETAIL ACCESS SUCCEEDED IN OTHER JURISDICTIONS AS CLAIMED BY CNESE?

A. I have not studied the issue in depth, and of course, it depends on your definition of "success." But, I don't automatically equate a lot of customers leaving an incumbent provider with "success." Any regulatory agency can create such "successes" if it raises the incumbent's rates high enough. Ohio is also reputed to be another "success." That was disputed by consumer advocates in that state, and as it is, the switching in that state has more to do with municipal aggregation and municipalization than customer choice.

Having a city council pick your provider is no more real customer choice than having your state regulator make that choice. Other states are just coming out of rate freezes that have insulated customers from market forces (e.g., Maryland and Illinois), so it is likely premature to draw any long-term conclusions, although I note that legislation is being proposed in Maryland to limit rate increases to 10% per year for residential customers once the freeze expires, which for one utility is later in 2004.

In any event, whether the Commission, after careful review, concludes that a state's retail access program has been a "success" or a "failure" or something in between, it should also take into consideration the circumstances existing in such states that may have contributed, perhaps critically so, to the outcome to determine whether those same circumstances exist or can be made to exist in Arizona. The Commission should also realize that it needs to study examples of both "success" and "failure," as well as examples of states that never decided to embark on retail to get a complete picture.

Q. ARE YOU SAYING THAT RETAIL ACCESS IS A FAILURE?

A. No. I am saying the Commission should carefully investigate claims by those standing to gain from retail choice as closely as it would those made by entities opposed to such choice. I am also saying that competition will require the Commission to make difficult trade-offs between those things it values about traditional regulation (reliability, stability, the ability to control prices and to maintain non-cost price disparities for social welfare or economic development purposes, etc.) with those values it hopes to achieve through competition. Many of these values are mutually exclusive. To simply say you want the "best of both" is unrealistic at best and bordering on disingenuous at worst.

B. Transmission Open Access

Q. DO YOU AGREE WITH CNESE'S ASSERTIONS CONCERNING TRANSMISSION ACCESS?

A. CNESE commented on the importance of ensuring open access to the Company's transmission system for all entities serving retail load within the APS service area on non-discriminatory terms. They also assert that the Company's Open Access Transmission Tariff "should continue to be administered and interpreted by the Arizona Independent System Administrator ["AISA"] to assure that [APS] direct access customers are treated in a non-discriminatory fashion with respect to transmission." (Fulmer Testimony at 21.)

The Company agrees with CNESE that APS should continue to provide non-discriminatory open access to its transmission system for ESPs serving APS direct access retail customers. Furthermore, we believe that our current OATT and proposed treatment of transmission service in this Application are consistent with and support this objective – going so far as to grant ESPs what could be viewed as preferential access. (A specified amount of transmission at the Palo Verde hub is "dedicated" to direct access, thus allowing ESPs to take all their deliveries at this most liquid of trading hubs rather than smaller *pro rata* amounts at each of the delivery points used by APS for Standard Offer customers.) And although APS does not call for the abolition of the AISA, we do disagree with CNESE that the AISA is necessary for this objective to be realized. Such open and non-discriminatory access is reflected in the Company's current OATT and cannot be changed without FERC approval. Additionally, the Company has supported the development of other FERC-approved regional transmission organizations, which would serve as a substitute for the AISA in interpreting the OATT.

IX. REVISED REVENUE REQUIREMENT

Q. WHAT IS THE COMPANY'S TEST PERIOD REVENUE REQUIREMENT TAKING INTO EFFECT ALL THE ADJUSTMENTS MADE OR AGREED TO IN THE COMPANY'S REBUTTAL TESTIMONIES?

A. APS originally requested an annual increase in base electric revenues of approximately $166.8 million. To that was added a surcharge of some $8.3 million per year for five years to collect previously-deferred costs associated with electric restructuring and the Electric Competition Rules (the Competition Rules Recovery Charge or "CRCC"). After consideration of the additional or revised adjustments testified to by other Company witnesses, the base revenue requirement has increased to $185 million. However, APS is still limiting its base revenue increase request to the same $166.8 million. To that figure must be added both the CRCC and, if approved by the Commission, the additional System Benefits, DSM and Environmental Portfolio surcharges proposed by APS, Staff and RUCO.

X. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS TO YOUR REBUTTAL?

A. Yes. The Company has offered a point-by-point critique of the Staff and intervenor rate recommendations–recommendations which, if accepted, would severely cripple APS and threaten both long-term reliability and customer service. Such recommendations are often "out of step" with long-established practice both in Arizona and elsewhere and, especially as regards the issue of rate-basing the PWEC generation, would sacrifice a last opportunity to realize significant long-term net benefits for APS customers for the sake of eight months of power from the APS/PWEC Track B contract. To emphasize that point, APS has presented evidence of the value of the PWEC assets as compared with a wide array of alternatives ranging from new self-build to new buy to market reliance on PPAs – alternatives both created through sophisticated econometric modeling and taken from the actual results of the ongoing Company RFP. Finally, Staff and intervenors would have this Commission ignore the history, both of this industry and of the regulatory policies and decisions, that brought APS and PWEC to their present dilemma of bifurcation, write-offs and un-recovered costs, a set of circumstances which can be finally resolved in a manner that, in the Commission's own words, is "fair" to those such as the Company who were unquestionably harmed by the "change in direction" signaled by the Track A Order. (Decision No. 65154 at 22.)

This case presents the Commission with an important opportunity to establish certain clearly articulated regulatory policies addressing three fundamental resource planning and acquisition issues that have become more than a little shrouded in uncertainty as a result of first the effort to restructure and electric utility industry in Arizona, then the "change in direction" heralded by Track A, and lastly the Track B Order. These issues, simply put are: (1) how is APS to discharge its obligation to secure new resources for a fast-growing customer constituency; (2) to whom is that obligation owed; and (3) what ratemaking criteria will be applied to the Company's efforts to discharge that obligation.

The "preliminary inquiry" found, by Staff's own admission, no harm to APS customers. APS, however, would submit that the evidence presented by the Company shows its customers have greatly benefited by the actions of Pinnacle West and PWEC during this most-difficult period in the electric industry. And those actions have been demonstrated to be within both the "spirit" and "letter" of the 1999 APS Settlement, the Electric Competition Rules and the APS Code of Conduct.

This rate case is not the forum for a resolution of either the value or the cost of retaining retail access in Arizona. The Commission has established another docket for precisely that purpose. But whether in that docket or this, the Commission should ask proponents of retail access to show them the facts and circumstances regarding customer benefits and the distribution of such benefits (and burdens) to the various customer groups of the type served by APS.

Q. DOES THAT CONCLUDE YOUR WRITTEN REBUTTAL TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Increase in Gross Revenue Requirements
ACC Jurisdictional
Adjusted Test Year Ended 12/31/02
(Dollars in Thousands)

		Electric - Updated			
Line No.	Description	Original Cost	RCND	Fair Value	Line No.
1	Adjusted Rate Base	4,229,649	6,749,628	5,489,639	1
2	Adjusted Operating Income	255,213	255,213	255,213	2
3	Current Rate of Return	6.03%	3.78%	4.65%	3
4	Required Operating Income	367,134	367,134	367,134	4
5	Required Rate of Return	8.68%	5.44%	6.69%	5
6	Operating Income Deficiency	111,921	111,921	111,921	6
7	Gross Revenue Conversion Factor	1.6529	1.6529	1.6529	7
8	Adjusted Increase in Base Revenue Requirements	184,993	184,993	184,993	8
9	Requested Increase in Base Revenue Requirements /1/	166,807	166,807	166,807	9

/1/ Consistent with Schedule A-1 of the Company's June 30, 2003 filing.

CONFIDENTIAL SCHEDULE
Schedule SMW-2RB
REDACTED

LIST OF RFP BIDDERS

1.

2.

3.

4.

5.

6.

7.

8.

9.

ATTACHMENT 9

APS POSITION ON ISSUES RAISED BY INDUSTRY RESTRUCTURING

The Points of Agreement to the restructuring element of the Plan, which are set forth in Attachment 8 to this Agreement, deal with the electric utility industry in Arizona. APS believes cooperative legislative and regulatory actions at both the state and federal levels will be necessary to permit broader access to the generation market by retail customers of regulated public service corporations in Arizona. The steps proposed herein are presented by the Company as a balanced, comprehensive package, each part of which is dependent on the others. APS will not be committed to support any particular part in the event one or more other parts are dropped or materially changed in the legislative or regulatory processes. It is the Company's firm position that these issues must be addressed and resolved prior to allowing open access in the retail markets of Arizona public service corporations.

As APS has pointed out during the Commission's Docket on Competition In The Electric Utility Industry, a number of legislative, regulatory and market issues must be satisfactorily addressed for Arizona to benefit from the increased economic efficiency that competition potentially can produce. By its concurrence to the Points of Agreement in Attachment 8, Staff has likewise agreed to the importance of such issues. In addition, APS believes that the record should be clear as to its present position on industry restructuring. For consistency sake, the Company has divided its comments using the categorization of issues from Attachment 8. However, APS has retained its own descriptive titles when referring to specific issues.

PROCEDURAL AND SUBSTANTIVE MATTERS

Process for Considering Restructuring Issues

As indicated by its concurrence in Attachment 8, APS agrees that industry restructuring should be debated and resolved in an open process after consideration of all points of view. The Commission's Docket No. U-0000-94-165 provides an appropriate forum for this process, although as noted above, both the Arizona Legislature and the U.S. Congress (in addition to FERC) will be important players in any comprehensive industry restructuring.

Exclusive Service Rights

In Arizona, electric public service corporations are granted statutorily established Certificates of Convenience and Necessity by the Commission. Under the State's concept of "regulated monopoly," these certificates confer an exclusive and perpetual right to serve all customers within a delineated territory as long as the utility provides or is ready and willing to provide reasonable service at Commission-regulated prices, sometimes referred to as the regulatory compact. This territorial right has been characterized by the Arizona Supreme Court as a "vested property right" protected by the Arizona Constitution that cannot be condemned or otherwise "taken" without payment of adequate compensation. If the issue of compensation is adequately addressed, APS will support legislation that allows the Commission to open, on a "phased" basis, heretofore exclusive electric service territories in Arizona to competition from all regulated electric public service corporations.

Obligation To Serve

In return for exclusive territorial rights, public service corporations are generally required to serve all customers requesting service (whether profitable or not) in accordance with rules and regulations established by the Commission. This obligation to serve is an essential part of the regulatory compact and has required Arizona's electric utilities to anticipate customer growth, demand and usage and prudently invest in generation, transmission, distribution, and other utility assets. Unlike an enterprise in a fully competitive market, Arizona's electric public service corporations cannot decide unilaterally which markets they wish to serve, set the terms for providing such service, or determine whether or not to expend the capital funds necessary to meet future demands.

As customers gain access to other generation suppliers, this will require a symmetrical change in the obligation of incumbent suppliers so that the incumbent utility is not unfairly burdened with "provider-of-last-resort" status. A clear breach of the regulatory compact will occur if the obligation to serve (and associated cost burdens) remains on a particular utility, while its competitors are free to pick who, how, and when they wish to serve. Accordingly, APS will support appropriate modifications to service obligations of Arizona public service corporations that recognize increasing customer options (at least with respect to generation) while still preserving the availability of reliable and affordable service.

Compensation Issues

Arizona public service corporations have rightful constitutional and equitable claims for compensation relative to recovery of stranded investment, compensable property rights and wheeling charges; specifically, compensation is due for:

(a) investments in assets prudently made, or commitments prudently incurred, by an Arizona public service corporation for the benefit of the customers in its service territory which becomes "stranded", i.e., non-recoverable, because of changes in the regulatory compact;

(b) investments "stranded" because of accounting or other regulatory changes occurring in the transition from a regulated monopoly environment to a competitive market;

(c) the loss of constitutionally protected property rights in an exclusive service territory conferred by the Commission pursuant to statute, both when the exclusiveness of such service rights is phased out as to a particular customer class and when the loss occurs as to a particular customer;

(d) wheeling services by an incumbent public service corporation for dedicating a portion of its "wires" capacity and ancillary services to accommodate a competitor's access to one or more retail customers within the incumbent's service territory, which compensation should reflect appropriate charges fully compensating the incumbent public service corporation for such service, regardless of whether such charges are regulated by FERC or the Commission.

In the economic proposal of the Plan, APS will take an important step towards mitigating its "stranded" investment by accelerating the amortization of "regulatory assets" over an eight (8) year transition period. The "7¢ Result" which represents the Company's goal to reduce its per kWh cost by a combination of aggressive cost containment and the development of new marketing opportunities, is another example of how APS hopes to mitigate the compensable damages it will experience upon the implementation of retail competition.

Federal-State Jurisdictional Uncertainties

Electric power commerce across the state and region is impeded by the jurisdictional uncertainty over the conflicting scope of federal versus state regulation in the utility industry. Therefore, at the federal level, APS, in cooperation with the industry and others, will seek congressional legislation that clarifies the right of states to authorize retail access and related terms and conditions of service and to effectively regulate such transactions when necessary. The Company will also seek clarification, through legislation or by FERC actions, that will clear the jurisdictional haze between the reach of federal control over transmission in interstate commerce and a state's critical ability to regulate and set retail rates.

Competitive Balance

Efficient competition will occur when all players, including out-of-state suppliers entering the Arizona market, are subject to the same rights and responsibilities, free from market-distorting special privileges, regulations or unequal burdens. APS will propose that any market entrant allowed into a previously exclusive territory of a regulated electric public service corporation pursuant to the legislation previously discussed regarding "Exclusive Service Rights" must itself be, or become, a public service corporation subject to appropriate Commission regulatory oversight and related obligations, including plant and line siting requirements (which should be administered directly by the Commission) and shared responsibility for maintaining service reliability. Such entrants could include out-of-state utilities, power marketers, independent power producers and other competitors.

Public Power Entities

The Arizona Constitution expressly excludes municipal corporations from the category of entities (public service corporations) which it subjects to regulation by the Commission. Due among other things to the uncertainties that any amendment of the Constitution would entail, the Company proposes to exclude municipal, tribal or other government-owned utilities from this restructuring proposal. Where such utilities have lawfully-conferred rights to serve all customers within a delineated territory, those rights would remain intact (i.e., would not be subject to being "phased" out as proposed above with respect to public service corporations); conversely, such utilities, by virtue of their not being public service corporations subject to Commission regulatory oversight and related obligations, would not be allowed competitive access to public service corporation territories in Arizona. However, it appears to APS that changes in law and relationships at the federal level, such as entitlements to preferential power from federal facilities or federal income tax advantages, could lead to a common interest in eliminating or reducing differences among utilities at the state level, thereby occasioning future reexamination of the difference proposed in this paragraph.

Reciprocal Trade Opportunities

Efficient competition and the public interest require that public service corporations be allowed the reciprocal opportunity to trade in each other's markets. The willingness of APS to open its service territory to competitors is contingent upon APS obtaining meaningful reciprocity from such competitors and their regulators. The Company's desire to remove barriers to entry into other state and regional markets can only be achieved through Commission and State support and involvement. The Company will urge federal legislation that will explicitly recognize the ability of states to condition the entry of out-of-state power suppliers into Arizona upon on reciprocal opportunities for Arizona public service corporations in other states. Finally, APS will support amendments to federal laws, such as the Public Utility Holding Company Act, to remove artificial and unnecessary restraints on utilities that desire to compete in regional and national markets.

Integrated Resource Planning

APS continues to support efficiency in electric usage, environmental protection and the Commission's Integrated Resource Planning ("IRP") process. Although the IRP is solidly grounded in traditional regulatory principles, many of APS' potential competitors are exempt from the IRP process. APS will ask the Commission to revise, consistent with the changes proposed herein, the current IRP process to recognize the emergence of competition and the need to maintain generation reliability in a system with proliferating suppliers. APS will continue to support cost-effective DSM and renewables as long as competitively neutral funding mechanisms are established.

Market Structure

The Company is, of course, aware of proposals in other jurisdictions for mandatory pooling of generation and for separation of generation and "wires" through mandatory divestiture.

APS believes mandatory pooling is another form of regulation, one which presumably would be beyond the bounds of Commission jurisdiction and which could well be more pervasive and onerous than current regulation and ultimately contrary to the interests of customers. APS believes that bilateral contracting (which could be tri-or-more lateral when aggregators and marketers are considered) will afford effective competition, particularly if and when facilitated by the emergence of an exchange mechanism such as the NY Mercantile Exchange.

Mandatory divestiture in the Company's judgment contravenes two important principles, one of an engineering nature and the other economic. System reliability depends on both generation and wires--some entity will have to control both to assure an effective operating system. The economic perspective is that there seems to be a natural tendency toward vertical integration in analogous situations: United Kingdom electric companies; telecommunications (where APS interprets the recent AT&T announcement of separation of its manufacturing and service functions as a move toward re-integration of local and long-distance services and facilities). Such a tendency is not necessarily anti-competitive; in the case of telecommunications, the opposite is probably true. Additionally, mandatory divestiture could require a complete restructuring of contract rights under the Company's mortgage indenture and other financing instruments; furthermore, such divestiture would be extremely expensive to implement, and could result in significant economic dislocation among customers, bondholders and shareholders, with no proven customer benefit.
The policy goal should be an efficiently functioning generation market, free from concentration of market power and from abuse of a monopoly asset (such as transmission). APS does not believe this goal is served by mandatory pooling (which may actually trend in the other direction), or that mandatory divestiture is the appropriate answer to the monopoly asset issue in view of the necessity for system reliability.

The market power issue is difficult to address without knowing the size of the market, but that should come into view by 2000. By then there will have been considerable experience with wholesale wheeling by way of FERC standard setting and adversarial proceedings. APS considers it unlikely that any Arizona-based electric utility will have excessive dominion over the relevant market as defined in 2000, or that the Commission will then need to do anything more about any wire monopoly in the field than what FERC will have by then already done in the wholesale field.

Phased Direct Retail Access

Assuming that the economic proposal of the Plan is approved, and that the foregoing issues have by then been resolved, APS would request the Commission to authorize access by retail customers of public service corporations to the broad generation market starting in the year 2000. For its system, APS would propose that initial access would apply to retail transmission customers receiving power at 69 kv or above. If this proves successful, it would be expanded approximately two years later by allowing access for all customers whose loads are greater than 3 mW and, by 2004, access for customers with demand in excess of 1 mW. Access for all remaining customers would be proposed at the appropriate time. APS would expect that other Arizona public service corporations would propose comparable retail access provisions that provide meaningful competitive opportunities. Such retail access would not necessarily "deregulate" utility service or eliminate the Commission's ultimate responsibility to public service corporations and their customers; it would, however, require modifications of the manner in which that oversight role is performed.

OUTCOMES

APS would like to emphasize the first three (3) of the "Outcomes" listed in Attachment 8.

It is critical that electric industry restructuring should be a careful and deliberative process that fully considers the economic, financial, operational, and system planning aspects of restructuring. This can be accomplished by addressing and resolving issues before rather than after or during the restructuring.

The goal of any industry restructuring should be increased efficiency, and hence lower costs. Restructuring "benefits" based on preditory pricing, cost shifting, or shareholder losses are illusory. APS' proposals to address the compensation issues and create competitive balance are intended to further an outcome based on increased efficiency.

Third, all major customer groups should be permitted to benefit from this increased efficiency. APS' proposals to maintain competitive balance, create reciprocal trade opportunities, and preserve the Commission's ability to effectively establish retail rates will help to make this preferred outcome more achievable.

APS proposes that the Commission specifically address and resolve these and other related issues through a series of hearings during 1996 (as contemplated by the Commission Staff in its Competition Docket) which will seek to develop appropriate legislative and regulatory solutions to these barriers. These hearings would be held independent from the Commission's consideration of the Agreement described above. APS believes that Commission action, in consultation with interested parties, can produce a set of regulatory and legislative reforms that can be presented to the Arizona Legislature and to the U.S. Congress in 1997. However, APS recognizes that the foregoing issues are difficult ones, legally and politically, and that their resolution will require time, particularly at the federal level.

APS-3R

EXHIBIT

APS-3R
admitted

REBUTTAL TESTIMONY OF DONALD E. BRANDT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

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REBUTTAL TESTIMONY OF DONALD E. BRANDT
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Donald E. Brandt. I am Executive Vice President and Chief Financial Officer for both Pinnacle West Capital Corporation ("Pinnacle West") and Arizona Public Service Company ("APS" or "Company"). I am responsible for the finance, treasury, accounting, tax, investor relations, financial planning, and power marketing and trading functions at Pinnacle West and APS. My business address is 400 North 5th Street, Phoenix, Arizona, 85004.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelor of Science degree in business administration with a major in accounting from St. Louis University in 1975. Before joining Pinnacle West and APS in 2003, I was Senior Vice President and Chief Financial Officer of Ameren Corporation, the parent company of the electric and gas utilities Union Electric Company (d/b/a AmerenUE) and Central Illinois Public Service Company (d/b/a AmerenCIPS). On numerous occasions, I have provided testimony before the Federal Energy Regulatory Commission ("FERC"), the Missouri Public Service Commission, and the Illinois Commerce Commission.

Before joining Union Electric Company in 1983, I was a manager with Price Waterhouse where I provided audit and consulting services to public companies, with a concentration in the utility industry. I am a certified public accountant and a member of the American Institute of Certified Public Accountants and the Arizona Society of Certified Public Accountants.

Q. DID YOU PREVIOUSLY SUBMIT WRITTEN TESTIMONY IN THIS RATE PROCEEDING?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will address the dramatic negative impact on the financial integrity of both APS and Pinnacle West if the Arizona Corporation Commission ("Commission") were to adopt the recommendations of either the Commission's Utilities Division Staff ("Staff") or the Residential Utility Consumers Office ("RUCO"). I will then discuss the impact that can be expected on equity and debt investors if either Staff's or RUCO's return on equity ("ROE") recommendation is adopted, and will respond to Staff's reliance on current low interest rates to justify the lowest ROE in the country. I will then provide highlights of the strong negative reaction from the financial community to Staff's recommendations.

Additionally, I will address certain of Staff's conclusions drawn from the preliminary inquiry into APS, Pinnacle West and Pinnacle West Energy Corporation's ("PWEC") actions related to the transition to electric competition. Specifically, I will clarify certain misunderstandings that Staff apparently has about the contingent credit ratings obtained by PWEC.

Finally, I will respond to Staff's recommendations regarding the Company's capital structure and explain why utilizing the Company's actual end-of-test-year period "50/50" capital structure is appropriate.

II. <u>SUMMARY</u>

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. We are in the midst of one of the most turbulent business cycles in recent utility and energy industry history. The financial markets have reacted by becoming increasingly conservative and demanding in their evaluation of the financial condition of such companies. In the environment of re-regulation in which we exist today, the financial community is especially sensitive to the impact of regulatory decisions on utilities. Implementation of Staff's or RUCO's recommendations not only will preclude the Company from earning a fair return, but it also will ensure that the Company cannot meet the financial criteria needed to maintain investment grade credit ratings – APS will sink to a "junk" rated company. This will have a dramatic and negative impact on APS' ability to finance projects needed to maintain reliable service for our customers and the continued economic growth of the state of Arizona would be at risk.

Over the next ten years, APS will need to access the capital markets to finance \$2.7 billion of debt. The certain degradation of APS' credit ratings that would result from the implementation of Staff's or RUCO's recommendations would cause an immediate annual increase of \$88 million in additional interest expense. That interest expense increase would reach \$114 million annually over the next ten years. On a cumulative basis, this translates to an additional \$1.06 billion in interest expense between 2005 and 2015 – an increase that would be passed on to customers. Unfortunately, if either the Staff or RUCO recommendations are adopted, the cost increases I describe are a **best** case scenario. There is absolutely no reason to have any confidence that APS could actually issue almost \$3 billion of junk bonds because, at times, the junk bond markets are closed to virtually all issuers. If such a closed market environment coincided with a significant APS liquidity need, the financial consequences could be catastrophic.

As I read the conclusions set forth in Staff witness Linda Jaress' direct testimony, it became clear Staff does not have a complete understanding of the process PWEC went through to obtain contingent credit ratings and what value those contingent ratings afforded PWEC and Pinnacle West. Importantly, neither PWEC nor any other entity could issue debt with a **contingent** credit rating. In PWEC's case, the ratings were contingent upon the transfer of the APS generating facilities to PWEC. After the actual transfer had occurred, the rating review process would have been repeated before the rating agencies would assign **actual** credit ratings. In other words, Pinnacle West would have again presented the PWEC business model with updated market forecasts and assumptions, including a final, executed Purchase Power Agreement ("PPA") with the requisite regulatory approval, if applicable. The rating agencies would then assign **actual** credit ratings based on their independent analysis of the long-run creditworthiness of PWEC at that point in time. Only with these **actual** credit ratings in hand, could PWEC have issued debt securities. In summary, Staff's conclusions on this subject set forth in Ms. Jaress' direct testimony are simply not supportable. In presentations and communications with the credit rating agencies, PWEC representatives acted professionally and appropriately and did not mislead rating agency representatives or in any manner subvert the ratings process.

III. FINANCIAL IMPACT OF STAFF'S AND RUCO'S RECOMMENDATIONS

A. *Overview*

Q. PLEASE SUMMARIZE HOW THE FINANCIAL COMMUNITY'S VIEW OF THE ELECTRIC INDUSTRY CHANGED BETWEEN 2000 AND TODAY?

A. In 2000, the industry was at the top of a boom cycle. Many entities that had been operating within what was generally a fully-regulated environment had formed non-regulated affiliates in anticipation of the restructuring of the industry that was occurring across the country. Regional market conditions had driven up spark spreads and inflated forward price curves resulting in speculative power plant development. The participants in that market were highly-rated, financially-robust companies that had ready access to the debt capital and bank credit markets. Financial institutions enthusiastically supported the extension of credit. By mid-2001, however, the California market experienced its implosion and the resulting FERC price caps put the brakes on this rapid development. The financial community became concerned about what they now viewed as an over-built market. Then, in late 2001, problems encountered by various high-profile energy market players (*e.g.*, Enron, Dynegy and Mirant) caused a rapid deterioration in the perception of the credit quality of the electric industry. As restructuring was halted, and reversed in some cases, financial institutions and the rating agencies began to focus again on the regulatory environment in which companies operate. They started to examine more closely the nature of the relationships between the companies and their regulators.

Q. HAS THE COMPANY ANALYZED APS' FINANCIAL RESULTS IF STAFF'S OR RUCO'S RECOMMENDATIONS WERE TO BE ADOPTED BY THE COMMISSION?

A. Yes, we have. APS certainly would lose its investment grade credit ratings and sink to non-investment grade, "junk" credit rating status. Our analysis shows that if either Staff's or RUCO's recommendations were adopted, the Company's leverage ratios (Debt / Total Capital and Funds From Operations / Average Total Debt) and interest coverage ratios (Pre-Tax Interest Coverage and Funds From Operations Interest Coverage) would fall, for the first time in the Company's history, to non-investment grade levels, leading to a dramatic downgrade in APS' credit ratings.

Q. WHAT IS A CREDIT RATING AGENCY?

A. A credit rating agency is a firm that provides its opinion on the creditworthiness of an entity and the financial obligations (such as bonds, preferred stock, and commercial paper) issued by that entity. Credit rating agencies whose credit ratings are used under the U.S. Securities and Exchange Commission's ("SEC") regulations are known as "Nationally Recognized Statistical Rating Organizations" or "NRSROs." There are currently four NRSROs — Dominion Bond Rating Service Ltd. ("DBRS"), Fitch, Inc., Moody's Investors Service ("Moody's"), and the Standard & Poor's Division of the McGraw Hill Companies Inc ("S&P").

Generally, long-term debt credit ratings distinguish between investment grade and non-investment grade. For example, a credit rating agency may assign a "AAA" credit rating as its top "investment grade" rating for corporate bonds and a "BB" credit rating or below for "non-investment grade" or "junk" corporate bonds. Rating designations of both Fitch and S&P have "BBB-" as the lowest investment-grade rating and "BB+" as the highest non-investment-grade rating. Comparable rating designations of Moody's are "Baa3" and "Ba1", respectively.

Commercial paper[1] credit ratings are designated by S&P as "A-1", "A-2", "A-3", and "B", with "A-1" indicating the highest quality rating and "B" the lowest. Moody's comparable ratings designations are "Prime-1", "Prime-2", "Prime-3", and "Not Prime" (abbreviated as "P-1", "P-2", "P-3, and "NP"). There is no market for commercial paper rated below "A-3" by S&P or "P-3" by Moody's.

Q. WHICH CREDIT RATING AGENCIES ISSUE CREDIT RATINGS ON THE DEBT OF PINNACLE WEST AND APS?

A. Moody's, S&P, and Fitch. Moody's and S&P both issue credit ratings under a formal client relationship whereby for their independent analytical purposes, they

[1]Commercial paper is a short-term, unsecured promissory note with a maturity ranging from 1 to 270 days commonly issued by corporations to finance working capital requirements. Because the notes are unsecured, the commercial paper market is dominated by large corporations with investment grade credit ratings.

have access to our nonpublic financial forecasts and data. Fitch issues credit ratings based solely on their access to publicly available financial information, data and news.

Within the publicly traded debt markets, Moody's and S&P are the most widely recognized. With rare exception, every mutual fund, insurance company, and other institutional debt investor will require an entity to obtain a credit rating from Moody's and S&P before it considers investing in that entity's debt securities. Fitch credit ratings also are valued by many institutional investors, particularly when debt securities have some unique, unusual provision or when debt securities are issued as a "private placement." A "private placement" is the issuance of a security that has not been registered with the SEC. Such securities can only be issued to small numbers of institutional investors and, after initial issuance, are subject to stringent SEC trading restrictions.

Q. WHAT ARE THE CURRENT CREDIT RATINGS FOR PINNACLE WEST AND APS?

A. The credit ratings are set forth in the table below:

	Moody's	S&P	Fitch
Pinnacle West Capital Corporation			
Senior Unsecured Debt	Baa2	BBB-	BBB
Commercial Paper	P-2	A-2	F-2
Ratings Outlook[2]	Negative	Negative	Negative
Arizona Public Service Company			
Senior Secured Debt[3]	A3	A-	A-
Senior Unsecured Debt	Baa1	BBB	BBB+
Secured Lease Obligation Bonds	Baa2	BBB	BBB
Commercial Paper	P-2	A-2	F-2
Ratings Outlook[2]	Negative	Negative	Negative

Within the spectrum of investment grade debt, the financial markets consider the above ratings to be of medium to low quality.

B. Staff's Recommendations

Q. LET'S FIRST DISCUSS THE IMPACT OF STAFF'S RECOMMENDATIONS. HAS THE COMPANY PREPARED A FORECAST OF WHAT WOULD HAPPEN TO THE COMPANY'S CREDIT RATING FINANCIAL BENCHMARKS UNDER STAFF'S RECOMMENDATIONS?

A. Yes. Based on the forecast results summarized in APS witness Don Robinson's testimony, I have included below APS' projected results for the benchmarks that

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[2] Ratings outlook indicates the possible direction a rating may move over the intermediate to longer term. "Positive" indicates ratings may be raised; "Negative" indicates ratings may be lowered; and "Stable" indicates ratings are not expected to change.

[3] APS plans to eliminate its senior secured (mortgage) debt within the next two months. Accordingly, senior secured debt ratings will be terminated.

S&P uses to gauge a utility's credit ratings. Our analysis is focused on S&P benchmark criteria because S&P publishes its specific utility financial benchmark targets, whereas Moody's does not. However, it is very reasonable to assume that a Moody's rating will track an S&P rating because Moody's ratings rarely differ from S&P ratings by more than one rating step up or down.

Q. WITH RESPECT TO THE S&P BENCHMARKS, WHAT DO APS' RESULTS LOOK LIKE UNDER THE STAFF'S RECOMMENDATIONS?

A. The APS results for 2005 are the most relevant because they include a full year's impact of Staff's recommended revenue decreases. Using the numerical results set forth in Mr. Robinson's testimony, the APS results for 2005 and their corresponding S&P credit rating categories are as follows:

S&P Benchmark	APS Result	S&P Category
Debt to total capital	61.6%	BB
Funds from operations to average total debt	12.2%	B
Pre-tax interest coverage	1.8x	BB
Funds from operations interest coverage	2.8x	BB

Q. IN DETERMINING CREDIT RATINGS, DO THE CREDIT RATING AGENCIES LOOK AT MORE THAN THE FINANCIAL METRICS YOU'VE JUST DETAILED?

A. Yes. The determination of credit ratings is more than just a mathematical exercise. As APS witness Steven Fetter discusses in his rebuttal testimony, the rating agencies consider both qualitative and quantitative factors in determining specific credit ratings. The rating agencies look at the financial metrics of a company and also consider trends in the financial data. They review financial projections and make an independent assessment as to the likelihood of various future financial outcomes. In addition to this quantitative analysis, they do extensive qualitative analysis. The rating agencies assess the regulatory environment in which a regulated utility operates, the various business and financial risks a company faces, and the utility's management and their prior track record. After putting all these factors together, the rating agencies then determine a company's credit ratings. Moody's addresses this aspect of credit ratings on its website (Moodys.com):

> Because it involves a look into the future, credit rating is by nature subjective. Moreover, because long-term credit judgments involve so many factors unique to particular industries, issuers, and countries, we believe that any attempt to reduce credit rating to a formulaic methodology would be misleading and would lead to serious mistakes.
>
> That is why Moody's uses a multidisciplinary or "universal" approach to risk analysis, which aims to bring an understanding of *all* relevant risk factors and viewpoints to every rating analysis.

Q. AFTER CONSIDERING ALL THE FACTORS INVOLVED IN DETERMINING CREDIT RATINGS, WHERE WOULD YOU EXPECT APS' CREDIT RATINGS TO FALL IF STAFF'S RECOMMENDATIONS WERE ADOPTED?

A. I believe APS' credit ratings would be no higher than BB and very possibly only B, both of which are below investment grade. Accordingly, under Staff's or RUCO's recommendations APS would be viewed as a "junk" credit. The financial metrics and trends would no longer support an investment grade credit rating. The demonstrable lack of constructive regulatory policy, as well as the increased financial and business risks, also would play key roles in the downgrading of APS.

Q. WHAT DO YOU MEAN BY A "DEMONSTRABLE LACK OF CONSTRUCTIVE REGULATORY POLICY" AND "INCREASED FINANCIAL AND BUSINESS RISKS"?

A. First, keep in mind that I use those words in the context of an assumption that Staff's recommendations are adopted. With that said, the rating agencies would assess Arizona regulation in the context of an electric utility, serving one of the fastest growing service territories in the United States, second only to Las Vegas, that is unable to rate base, much less earn a fair return on, generating units for which there is a clear, demonstrated need. Further, they would see a utility with a large and growing exposure to the wholesale generation market and with a large and growing dependence on highly volatile natural gas prices, that is not afforded a purchased power and fuel adjustment mechanism to allow it to recover prudently incurred costs on a timely basis. Looking into the future, and factoring in Arizona's continuing rapid growth, the rating agencies would have severe doubts about the Arizona regulatory process ever being able to constructively address the financial realities of the infrastructure needs of a rapidly growing region. I can assure you that our location in the West, and our proximity and similarity to Las Vegas, would be at the forefront of their evaluation process. Since the Staff filed its recommendations, discussions we have had with rating agency representatives, equity analysts and institutional investors have included a line of questioning posed to us that can be summarized as, how can we be assured that this situation will not turn into another Nevada Power.

Q. IN LIGHT OF THE ABOVE SUMMARY, WHAT IMPACT DO YOU THINK THE ADOPTION OF STAFF'S RECOMMENDATIONS WOULD HAVE ON APS' COST OF DEBT AND ACCESS TO THE CAPITAL AND BANK MARKETS?

A. As I described above, if the Commission adopted Staff's recommendations, APS would be downgraded to below investment grade and become a "junk" credit. The impact would be immediate and costly on a number of fronts:

1) Given the seasonal nature of APS' cash flows, there is a heavy reliance on commercial paper for working capital needs. APS averages about $100 million of commercial paper outstanding. However, the Company reaches a maximum outstanding of about $250 million each June, prior to the inflows of the summer revenues. APS' commercial paper rating is currently A-2 and Prime-2 (P-2) by S&P and Moody's, respectively. After the downgrade, APS' ratings would fall to "B" and "Not Prime." At that ratings level, there are no investors for commercial paper. APS would immediately

lose its access to the commercial paper markets for meeting short-term borrowing needs. In addition, the daily liquidity that the commercial paper market offers would be lost. Rather than taking advantage of the daily flexibility afforded by the commercial paper markets, APS would have to issue a large, fixed amount of junk bonds to satisfy its daily working capital needs, likely resulting in an "over-borrowed" situation most times during the year. Such a situation also would increase the overall cost of borrowing, thereby increasing APS' cost of capital, and ultimately would increase costs for our customers.

2) APS has $27 million of tax-exempt debt outstanding under a "remarketing" program whereby the securities are effectively issued with a 1-day maturity, with the intention that the securities will be continuously remarketed each day, until their ultimate maturities which occur in 2031 ($7 million) and 2034 ($20 million). The annual interest rate on this debt currently is in the 1% to 1.5% range. Thus, the Company currently is able to take advantage of extremely attractive short-term, tax-exempt interest rates, under the "umbrella" of a very long-term debt instrument. In addition, APS has $164 million of tax-exempt debt outstanding under a similar remarketing program that remarkets the securities on an annual basis, rather than on a daily basis, until their ultimate maturity in 2029. The annual interest rate on this debt currently is approximately 2%.

Similar to the $27 million debt discussed above, APS has another $196 million of tax-exempt debt outstanding under a daily remarketing program, with ultimate maturities in 2024 through 2033. However, this debt requires bank letters of credit ("LOCs") to support its creditworthiness. These LOCs require periodic renewal with the issuing banks, the most distant renewal date being October 2005. The interest rate on this debt currently is approximately 0.9%.

The tax-exempt debt market demands very high quality issuers. Even at its current BBB rating, APS has had difficulty finding investors in recent years. APS would be unable to remarket these securities or renew the bank LOCs if it were rated a "junk" credit. As a result, this total of $387 million of tax-exempt debt would become payable at the next remarketing dates. APS would have to turn to the junk bond market to issue at least $387 million of taxable junk bonds to pay off the $387 million of maturing tax-exempt debt. Rather than enjoying the 0.9% to 2.0% tax-exempt interest rates, the interest rate on the new junk debt would be in the range of 8% to 10%. APS' annual interest costs would increase by approximately $24 million, and the tax-exempt interest cost advantage of the original debt would be lost forever.

3) APS needs to refinance $400 million of maturing bonds in 2005. In total over the next 10 years, APS has approximately $1.56 billion of long-term debt maturities that would need to be refinanced. In addition, APS has extensive needs to access the capital markets over the foreseeable future to finance on-going transmission, distribution and generation-related construction programs. APS currently projects capital expenditures to total $1.2 billion in 2005 and 2006 alone. APS would no longer be able to fund its capital expenditures with cash flow from normal operations and would have to raise an additional $400 million just to finance capital expenditures over the next two years. APS would have no alternative but to turn to the "junk" bond market to finance this combined $2 billion of capital needs. As a result, our annual financing costs would increase $62 million over what they would have been if APS had not suffered the credit rating downgrade to "junk" status.

4) The August 1986 Palo Verde Unit 2 sale/leaseback agreements require that APS provide LOCs totaling $107 million to protect the equity lessors. The current LOCs expire in 2005. With a "junk" credit rating, APS would be unable to renew the LOCs. Under the terms of the sale/leaseback agreements, failure to renew the LOCs would trigger a default that would require APS, at a minimum, to buy out the equity lessors at the higher of $136 million, the agreements' "extraordinary casualty value", or the "fair market value" of the equity lessors' interest in Palo Verde Unit 2. As specified in the agreements, APS and the equity lessors would have a fifteen (15) day window to negotiate this payment. If the payment were not negotiated within the fifteen-day window, the entire sale/leaseback transaction would be unwound, triggering a total payment by APS of $443 million. Again, APS would have to turn to the "junk" bond market, and assuming a payment of only $136 million, adding another $11 million to annual interest costs to be passed on to APS customers. I believe it is reasonable to assume the actual negotiated payment would be far in excess of the $136 million, however, because the equity lessors would understand the advantage they would have in the negotiations. APS would have a $443 million "gun to its head."

5) Adding to the already dismal financial situation is the fact that APS has significant reliance on bank credit in the form of a $250 million revolving credit agreement syndicated among 14 banks, subject to renewal on an annual basis. In addition, APS has the LOCs for tax-exempt bonds and for the sale/leaseback that I described earlier, along with insurance agreements supporting other tax-exempt bonds. These credit agreements contain pricing grids whereby the financing costs are dependent on the credit ratings of APS. Lower ratings result in higher costs. As a result, APS would

immediately see an increase in pricing of 42 basis points, equivalent to an annual cost increase of $3 million. Most banks do not lend to non-investment grade companies. In evaluating the creditworthiness of APS, the banks go through an analytical process comparable to that utilized by the rating agencies. The forecasted weak cash flow and financial metrics, as well as the unsupportive regulatory environment, would cause most banks to "run for the hills" when the credit agreement was up for renewal. The few that might renew would charge significantly higher prices and would add extremely onerous covenants that, in the event of further financial stress, could potentially take APS to the brink of default and bankruptcy.

6) As if there wouldn't be enough financial distress already, APS' Marketing and Trading ("APSM&T") would suffer as a result of the downgrade to non-investment grade. As is typical in the energy trading business, most of APS' agreements with energy trading counterparties require, in the event of a downgrade that would take APS' credit rating below investment grade, that APS provide the counterparty with cash collateral to cover the difference between the contract price and the then-existing market price of the commodity. These contractual provisions are referred to as "collateral calls." Moody's highlighted this issue in its October 2002 publication, *U.S. Electric Utilities – 2002 Industry Outlook*:

> ...the energy merchant sector carries significant liquidity risk due to its confidence-sensitive nature and to the system of credit allocation among energy traders that requires collateral postings in the event of rating downgrades. The structure relied on by the industry creates a type of pernicious rating trigger that became a key factor in creating distress situations for several energy traders. The existence of explicit and implicit rating triggers in most commercial contracts among the traders ensures that counterparty contracts either unwind or require additional cash collateralization if credit ratings decline below investment grade. As downgrades below investment grade occurred due primarily to Moody's concerns about weak cash flow generation from most energy merchant companies, the result was a sudden and precipitous call on liquidity at a time that these companies were least able to access the market.

In addition to market price collateral calls, trading counterparties place other onerous terms on their dealings with non-investment grade companies. APS would be forced to prepay for a large amount of the Company's power plant fuel needs. Any form of longer-term commodity agreement would require the Company to provide up-front collateral. This would significantly increase our costs of doing business in the wholesale markets and make it much more difficult to hedge our positions, further increasing our risk profile. As an example, APSM&T regularly transacts with "junk' rated Nevada Power, but requires Nevada Power, on a weekly basis, to pay 100% in advance.

Q. REGARDING THE POINTS YOU RAISED IN THE PREVIOUS QUESTION, COULD YOU SUMMARIZE THE IMPACT ON APS FINANCING COSTS?

A. Yes. The certain degradation of APS' credit ratings that would result from the implementation of Staff's or RUCO's recommendations would cause annual interest expense to increase immediately approximately $88 million. That interest expense increase would escalate to approximately $114 million annually over the next ten years. On a cumulative basis, this would accumulate to an additional $1.06 billion in interest expense over the next ten years that would be passed on to customers. The following table details the components of these increases (all amounts are $ millions):

	Debt Amount	Increase in 2005 Annual Interest Expense	Increase in 2015 Annual Interest Expense
Commercial Paper	**$250**	**$17**	**$17**
Tax-Exempt Debt	**387**	**24**	**24**
Taxable Debt	**1,958**	**36**	**62**
Sale/Leaseback	**136**	**11**	**11**
Total	**$2,731**	**$88**	**$114**
Cumulative Total			**$1,056**

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE IMPLICATIONS OF APS' CREDIT RATINGS SINKING TO BELOW INVESTMENT GRADE, OR "JUNK"?

A. Yes, I do. APS is the operator and partial owner of the Palo Verde Nuclear Generating Station, the largest nuclear generating station in the United States. Implementing a rate recommendation that would turn the operator of this country's largest nuclear facility into a "junk" credit could not be sound public policy.

Q. ARE YOU FAMILIAR WITH STAFF'S ASSERTION THAT THEIR RECOMMENDATIONS WILL ALLOW THE COMPANY TO ACHIEVE A PRE-TAX INTEREST COVERAGE RATIO OF 3.1 TIMES?

A. Yes. In Staff witness' Joel Reiker's schedule JMR-8, he divides the grossed up (*i.e.*, adjusted to reflect the revenue requirement attributable to income taxes) Staff recommended cost of capital of 9.8% by Staff's weighted cost of debt of 3.19% to derive the 3.1 times pre-tax interest coverage ratio. Another way of reflecting Mr. Reiker's calculation of the coverage ratio is to work in dollars instead of percentages. The numerator would be calculated as follows:

> $3.051 billion Staff rate base x 9.8% Staff grossed up cost of capital = $299 million Staff revenue requirements to cover debt and equity returns

The denominator would be calculated as follows:

> $3.051 billion Staff rate base x 3.19% Staff weighted cost of debt = $97 million of annual interest expense

The pre-tax interest coverage ratio would be calculated as follows:

> $299 million revenue requirements for debt and equity / $97 million interest expense = 3.1 times.

Q. IS ANYTHING WRONG WITH THIS CALCULATION?

A. Yes. It omits several key elements of a proper interest coverage calculation, is inconsistent with the interest coverage methodology used by the credit rating agencies, and is therefore neither meaningful nor useful.

For businesses that lease significant assets, such as the Company does with Palo Verde Unit 2, S&P requires adjustments to debt and coverage ratios to reflect the imputed interest component of lease payments. S&P requires this adjustment because leases are very similar to debt , *i.e.*, fixed obligations that cannot easily be reduced or eliminated, and implicitly, a lease payment consists of a principal component and an interest component. For the test year 2002, such an adjustment would add $41 million to both the numerator and denominator in the Company's pre-tax interest coverage calculation to reflect imputed interest component of the Palo Verde Unit 2 lease payment. Adding the $41 million to Staff's numerator and denominator would change their ratio to (299+41) / (97+41) = 2.5 times pre-tax interest coverage, which is at the bottom end of a BBB rating.

Q. WHAT ELSE IS WRONG WITH THIS CALCULATION?

A. Staff's calculation utilizes a substantially understated, erroneous interest expense amount of $97 million. The interest expense, or fixed charge, amount utilized in the calculation should be $178 million: the combination of (1) APS' actual 2002 interest expense of $137 million and (2) the $41 million S&P Palo Verde lease adjustment I refer to above. As I mentioned earlier, when we reflect Staff's recommended rate decrease in our forecast for 2005, we calculate APS' pre-tax interest coverage ratio to be 1.8 times, in the BB non-investment grade range, dramatically worse than Staff's calculation of a pre-tax interest coverage ratio of 3.1 times.

Q. ARE THERE ANY OTHER PROBLEMS WITH STAFF'S ESTIMATE OF THE PRE-TAX INTEREST COVERAGE THEIR RECOMMENDATIONS WOULD GENERATE?

A. Yes. Because Staff is recommending that the Company not be allowed to put the PWEC dedicated units into rate base, APS will have to buy more power from the market. If APS enters into long-term purchased power agreements to meet those needs, S&P will impute a fixed charge to add to the pre-tax interest coverage ratio calculation. The S&P methodology for such adjustments is described in their May 8, 2003 publication, *"Buy Versus Build": Debt Aspects of Purchased-Power.* For example, if APS entered into a 20-year purchase power agreement with a $50 million per year capacity payment, the adjustment calculated consistent with the methodology prescribed by S&P would impute an additional fixed charge of $21 million to add to the pre-tax interest coverage ratio calculation. If the capacity charge is $100 million per year, the fixed charge adjustment to the pre-tax interest coverage ratio would be $43 million. Inclusion of such an adjustment would further deteriorate the interest coverage ratios.

C. RUCO's Recommendations

Q. WITH RESPECT TO THE S&P BENCHMARKS, WHAT DO THE APS RESULTS LOOK LIKE UNDER RUCO'S RECOMMENDATIONS?

A. Again, I will focus on the APS results for 2005 for the reason explained earlier. Under RUCO's recommendations, using the numerical results set forth in Mr. Robinson's testimony, the APS results for 2005 and their corresponding S&P credit rating categories are as follows:

S&P Benchmark	APS Result	S&P Category
Debt to total capital	**60.6%**	**BB**
Funds from operations to average total debt	**13.9%**	**B**
Pre-tax interest coverage	**2.1x**	**BB**
Funds from operations interest coverage	**3.1x**	**BBB**

Q. ARE YOU FAMILIAR WITH RUCO'S STATEMENT THAT ITS PROPOSAL WILL ALLOW THE COMPANY TO ACHIEVE A PRE-TAX INTEREST COVERAGE RATIO OF 3.28 TIMES?

A. Yes. RUCO's pre-tax interest coverage ratio suffers from the same shortfalls in methodology that Staff's assertion does and, as a result, it too is neither meaningful nor useful. As is indicated in the table above, if the RUCO recommendations were adopted, APS' pre-tax interest coverage ratio would be only 2.1 times, in the BB non-investment grade range.

Q. WHAT ARE THE FINANCIAL IMPLICATIONS IF THE COMMISSION ADOPTED RUCO'S RECOMMENDATIONS?

A. The financial implications I outlined earlier in relation to the acceptance of the Staff's recommendations also would apply if RUCO's recommendations were accepted. APS would be downgraded to non-investment grade, resulting in a similar severe financial distress. Although it may appear that RUCO's recommendations are better than Staff's because the level of rate reduction is less, both RUCO's and Staff's recommendations result in APS becoming a "junk" credit. Whether one falls off a 100-story building or an 80-story building, the result is still the same.

D. Impact on Pinnacle West

Q. HAVE YOU ANALYZED THE FINANCIAL RESULTS ON PINNACLE WEST IF STAFF'S OR RUCO'S RECOMMENDATIONS WERE TO BE ADOPTED BY THE COMMISSION?

A. Yes. Pinnacle West's credit ratings would be the same as or probably lower than APS' credit ratings. The parent company also would be viewed as a "junk" credit and would be in the BB or B range.

Q. IF PINNACLE WEST WERE RATED NON-INVESTMENT GRADE, WHAT WOULD BE THE IMPLICATIONS FOR PINNACLE WEST AND APS?

A. Pinnacle West would immediately suffer the same liquidity crisis and limited access to the debt capital and bank credit markets as APS. The parent company would suffer the negative impacts to a greater extent because its primary subsidiary also would be in financial distress. Pinnacle West would face a crisis related to its loss of access to the commercial paper markets, limited access to the taxable debt capital markets for new money or refinancings, and extreme difficulty in renewing its $305 million of bank credit facilities. The need to refinance the $500 million of inter-company debt owed by PWEC to APS would present an additional financial risk. Under Staff's recommendation to not rate base the dedicated units, the $500 million inter-company note becomes due and payable in May 2007. Absent investment grade ratings, Pinnacle West's options in refinancing the $500 million would be very limited and in all cases extremely costly. All of these factors would result in negative implications for APS because APS would not be able to rely on its parent to provide support in this period of financial distress. A default by Pinnacle West in any of its financing agreements would not result in a cross-default in APS debt instruments. However, a default under an APS debt instrument does cross-default the Pinnacle West debt.

We have spent much time discussing the pitfalls of APS falling below an investment grade credit rating. I do not believe the goal of this Commission should be to establish rate levels such that APS just barely qualifies for an investment grade credit rating. I have almost 30 years experience working within the finance function of electric utilities. I have been the chief financial officer of an electric utility for more than 15 years. Over that period of time, I have had experience working with a utility rated from "BBB-" up to a utility rated "AA-". I can assure you that both the range of financing options available and their related costs are far superior for a utility rated "A" or above, than they are for a utility rated below an "A". And once a utility is rated below investment grade, financing alternatives become extremely limited and the costs are exorbitant. In addition, at times the market for non-investment grade debt, the so-called "high-yield" or "junk bond" market, is closed for indefinite periods of time. If APS were to fall to a junk credit rating, there is absolutely no reason to have any confidence that we could successfully issue the several **BILLION** dollars of junk bonds that would be required. Looking to the future, with the strong growth inherent in APS' service territory and APS' continuing need to make capital investments to meet the growing energy needs of its customers, I believe APS needs to achieve a credit rating of "A" to provide APS with an appropriate level of financial flexibility to minimize its financing costs over the long term.

IV. RETURN ON EQUITY ("ROE")

Q. STAFF ASSERTS THAT THE CURRENT LOW INTEREST RATES JUSTIFY THEIR RECOMMENDATION FOR A 9% ROE. DO YOU BELIEVE A 9% ROE IS CONSISTENT WITH INVESTORS' EXPECTATIONS?

A. No, I do not. A good part of my job is maintaining contact with institutional investors. Over the past 20 years, I have dealt with institutional utility equity investors and developed a comprehensive, in-depth understanding of their expectations with respect to their utility investments. They expect a relatively stable or growing share price, growth in earnings, and growth in the common stock dividend. A 9% ROE will not support these investor expectations.

Q. WHAT IMPACT WOULD ADOPTION OF STAFF'S RECOMMENDATIONS HAVE ON THE PINNACLE WEST DIVIDEND AND PROSPECTS FOR FUTURE DIVIDEND GROWTH?

A. Pinnacle West's 2005 forecast earnings declined by 64% after we adjusted our financial forecast to reflect Staff's recommendations. This decline in earnings results in a dividend payout ratio (dividends/earnings) of 145%. Such a dividend payout ratio is not sustainable and would eliminate the possibility of dividend growth, and in all likelihood would result in a substantial reduction, if not total elimination, of the dividend. If the Pinnacle West dividend were reduced or eliminated, Pinnacle West' stock price would plummet. No reasonable person could assert that any knowledgeable investor in Pinnacle West stock ever expected this financial outcome.

Q. TURNING BACK TO THE STAFF'S RECOMMENDATION FOR A 9% ROE PREMISED ON CURRENT LOW INTEREST RATES, WHAT DO YOU BELIEVE WOULD BE CONSISTENT WITH THE EXPECTATIONS OF EQUITY INVESTORS?

A. As a basis for their investment expectations, equity investors give substantial consideration to the ROEs allowed other utilities and then adjust those ROEs for the unique risk profile of Pinnacle West and APS.

As an indication of what investors expect, Regulatory Research Associates reports the following data for average equity returns allowed electric utilities in each of the years 2001 through 2003. I have included a column that includes the average annual yield on the 10-year Treasury Bond for comparison purposes.

Year	Number of Observations[1]	Average Allowed Equity Return[1]	Average Yield on 10-year US Treasury Bond[2]
2001	18	11.09%	5.00%
2002	22	11.16%	4.58%
2003	22	10.97%	4.00%

[1]*See* Regulatory Research Associates, Inc., "Major Rate Case Decisions—January 2002—December 2003 Supplement Study, January 22, 2004.

[2]Per Federal Reserve data on www.federalreserve.gov.

As one can observe, the average of allowed ROEs over the last 3 years has been within a range of only 19 basis points (0.19%) and demonstrates only a 1.08%

decline in relative terms. Also, one can observe that over the same 3-year period, the average yield on the 10-year US Treasury bond demonstrated a consistent decline, dropping 100 basis points (1.0%), or a 20% decline in relative terms. This relatively stable average allowed ROE, in the face of declining interest rates, conflicts with Staff's conclusions and recommendation.

In addition, as Mr. Robinson explains, the average allowed ROE of 10.97% for 2003 includes six instances where the allowed ROE was 10.25% or lower. Each of these 6 instances reflect unique circumstances such as a low risk, "wires only" business situation. Excluding these 6 instances, the average allowed ROE for the remaining 16 instances is 11.39%.

Further, investors' expectations would effectively adjust these averages for the following unique attributes of Pinnacle West and APS that substantially increase risk:

- APS kWh sales are expected to continue to grow at about 3 times the national average, second only to Nevada Power, necessitating continual capital expenditures and access to the capital markets to meet the growing energy needs of APS customers.

- As a result of continuing kWh sales growth, APS will experience a continuously increasing dependence on natural gas as a fuel source. Risk will therefore continue to increase as a result of the highly volatile nature of natural gas prices. Investors recognize that such risks can be **partially** mitigated by the implementation of an appropriate regulatory fuel and purchased power adjustment clause, however.

- APS must rely on the wholesale energy markets for a significant portion of its energy needs. In addition, the western energy market is dominated by the influence of California. Growth originating in California is widely expected to drive the western energy markets to a capacity short position within the next few years.

- Staff recommendations that, if implemented, would cause APS credit ratings to plummet to non-investment grade "junk" levels.

- A Commission that has reversed course on restructuring initiatives but without yet settling fundamental "going forward" issues on resource procurement, cost recovery, customer choice, and infrastructure development.

Based on these factors, I believe it is reasonable to assume that investors in Pinnacle West common stock made their investment decisions based on an implicit assumption that the company would, at a minimum, be allowed to earn a ROE toward the upper end of the 11.25% to 11.75% range recommended by APS witness Charles Olson.

Q. DOES A LOWER GRANTED RETURN ON EQUITY ALSO IMPACT DEBT INVESTORS?

A. Yes. Fixed income investors and credit rating agencies look at both cash flow and income driven interest coverage ratios. Lowering a utility's revenue stream and return on equity lowers the coverage ratio for its interest payments on its debt. A bond investor would be more interested in purchasing the debt of a utility with a higher authorized ROE than one with a lower ROE, all else being equal, because the utility with the higher ROE would have a higher interest coverage ratio, which would give the debt investor greater protection against default.

V. <u>FINANCIAL COMMUNITY REACTION TO STAFF AND RUCO RECOMMENDATIONS</u>

Q. BEFORE ADDRESSING SPECIFIC RATING AGENCY REACTION TO STAFF AND RUCO RECOMMENDATIONS, PLEASE DISCUSS BRIEFLY HOW RATING AGENCIES HAVE REACTED IN OTHER CASES WHERE COMPANIES HAVE EXPERIENCED NEGATIVE REGULATORY OUTCOMES?

A. The rating agencies have reacted quickly and negatively when regulators have not been supportive of companies. Rating agency treatment of Pacific Gas and Electric Company in 2001 provides one example of how the agencies can react to negative regulatory outcomes. On January 4, 2001, the California Public Utilities Commission issued a rate order that included a 10% rate increase. The agencies viewed the order as failing to address the mismatch between what the utility was paying for electricity and what it was able to pass on to its customers. That same day, S&P lowered the company's corporate credit rating to "BBB-" from "A+," the secured debt ratings to "BBB" from "AA-," the unsecured debt ratings to "BBB-" from "A," and its commercial paper ratings to "A-3" from "A-1." The following day, Moody's lowered the company's issuer rating to "Baa3" from "A2," its secured debt ratings to "Baa2" from "A1," its unsecured ratings to "Baa3" from "A2," and its commercial paper ratings to "P-3" from "P-1."

Another example would be the rating agencies reactions to regulatory decisions regarding Sierra Pacific Resources. In March 2002, S&P downgraded the corporate credit rating of the company and its utility subsidiaries from investment grade to below investment grade stating that the downgrades "reflect the extremely negative decision issued today by the Public Utility Commission of Nevada." One month later, Moody's downgraded the debt ratings of the company and its utility subsidiaries due to what they referred to as "the very harsh decision."

Q. HOW DO THE RATING AGENCIES CONSIDER THE REGULATORY ENVIRONMENT IN WHICH RATED UTILITIES OPERATE?

A. Rating agencies consider the regulatory environment as a major factor in evaluating companies. In an article titled, "A Fresh Look at U.S. Utility Regulation" in S&P's *"Utilities and Perspectives"* publication, dated February 2, 2004, S&P states: "In the end, the regulation of public utilities is the defining element of the industry and is often the determinative factor in the ratings of a utility." In another article titled "DBRS Methodology in Rating Utilities," published in June 2002, DBRS describes its ratings methodology and notes that "one of the key factors in qualitative analysis is the quality of regulation."

Moody's November 2002 special comment report titled, *A Look at How Regulators Support U.S. Electric Utilities in States That Have Yet to Restructure*, dealt with "the extent to which regulators are supportive of electric utility credit quality." In the report, Moody's states:

> Common threads in the supportive jurisdictions include performance-based ratemaking mechanisms, automatic or annual adjustment clauses for recovery of changes in fuel and energy costs, the ability to permit interim or emergency rate relief, and reasonable authorized return on equity levels. As a result, regulation has had a largely neutral effect on the debt ratings of most electric utilities in these constructive state regulatory environments. By comparison, the credit ratings of the electric utilities providing service in somewhat restrictive regulatory jurisdictions have been under more pressure.

Q. HAVE THE CREDIT RATING AGENCIES REACTED TO THE TESTIMONIES FILED BY STAFF AND RUCO IN THIS RATE CASE?

A. Yes, and they did so quickly. S&P issued a bulletin in less than 24 hours of the filing of the testimonies clearly stating that implementation of Staff's recommendations could result in negative rating actions:

> ...if implemented by the commission, the recommendations could result in negative ratings actions...Such recommendations represent a significant departure from the direction indicated by the ACC in recent decisions that have supported APS' credit quality.
>
> Standard & Poor's
> February 4, 2004

On March 19, 2004, S&P announced that it had revised its ratings outlook for both Pinnacle West and APS from "stable" down to "negative." The S&P bulletin stated:

> The outlook revision reflects concern that consolidated financial metrics may weaken over the intermediate term. APS' pending general rate case is the critical immediate credit driver. Based on the precedent of recent constructive actions by the Arizona Corporation Commission (ACC), Standard & Poor's expects that the commission

> will act prudently to provide APS with a reasonable rate increase and establish a long-term procurement process to address the utility's need for significant new capacity in the next several years. Yet, cash flows appear vulnerable even under relatively modest stress cases.

The week after Staff and RUCO filed their testimonies, Moody's downgraded the rating outlook on APS from "Stable" to "Negative." In doing so, Moody's specifically noted:

> The change in rating outlook [to negative from stable] reflects the unfavorable recommendations offered by the Staff of the Arizona Corporation Commission (ACC Staff), and by the Arizona Residential Utility Consumers Office (RUCO)...the ratings of [Pinnacle West], APS and PVNGS could be placed under review for downgrade."
>
> Moody's Investors Service
> February 12, 2004

Q. HOW HAVE RATING AGENCIES REACTED IN THE PAST WHEN APS HAS EXPERIENCED A NEGATIVE REGULATORY OUTCOME?

A. In September 1983, the Commission issued Decision No. 53761 concerning an APS rate application wherein APS requested, among other things, an increase in CWIP to resolve chronic cash flow issues. The Commission denied the CWIP requests. Wall Street reacted quickly and very negatively. APS' long-term debt was downgraded from single "A" to "BBB+" (S&P) and "Baa2" (Moody's). APS' commercial paper rating also suffered negative consequences, falling to "P-2 " (Moody's) and "A-2" (S&P).

Q. IF APS WERE DOWNGRADED AS A RESULT OF THIS RATE DECISION, WOULDN'T THE COMPANY BE UPGRADED WITH THE NEXT POSITIVE RATE DECISION?

A. No, I don't believe so. Rating agencies are much more reluctant to increase ratings than to decrease them. As I mentioned earlier, the regulatory climate is a key component in determining the credit ratings of a regulated company. Regulatory decisions, as well as consistent regulatory policy, are key variables that rating agencies consider. The volatility of regulatory outcomes therefore adversely impacts credit ratings. Once the rating agencies have decided that the Company is in a "poor" regulatory climate, it is very challenging to get upgraded. A "good" regulatory decision next time just furthers the belief of the inconsistent nature of regulation. In fact, APS has never regained its credit ratings to the single "A" level of the early 1980's. Twenty years later, APS is still rated "A-2" and "P-2" for its short-term debt and is still a mid-BBB company. Rising from non-investment grade up to investment grade is an incredibly difficult task and would require a dramatic improvement in both financial and regulatory results.

Q. WHAT ARE THE RATING AGENCIES' POSITIONS ON PURCHASED POWER AND FUEL ADJUSTMENT CLAUSES AND WHAT IS THEIR LIKELY RESPONSE TO STAFF'S AND RUCO'S RECOMMENDATIONS OPPOSING THE POWER SUPPLY ADJUSTOR ("PSA")?

A. Rating agencies view creditworthiness in light of financial and business risks. In a November 14, 2002 S&P article entitled "Constructive Regulation for U.S. Utilities Is More Important Than Ever," the author highlights the importance of a PSA:

> When assessing the importance of productive regulation to the credit strength of an electric utility, something to consider is the means by which the utility can expect to recover variable expenses, particularly fuel and purchased-power expenses, which have highly erratic unit costs... In jurisdictions where fuel adjustment clauses have been prohibited, electric utilities have always been subject to the uncertainties surrounding the recovery of incurred fuel and purchased-power expenses. With few exceptions, companies operating exclusively in these jurisdictions have always had ratings below the industry average.

The credit rating agencies view the lack of a PSA as adding significant financial risk to the company, especially for a company located in an area with growing customer and load requirements such as Arizona. In the eyes of the rating agencies, the absence of a PSA would significantly weaken the financial profile of APS.

Q. HAVE WALL STREET EQUITY RESEARCH ANALYSTS REACTED TO THE STAFF AND RUCO RECOMMENDATIONS?

A. Yes. Following the filing of the Staff and RUCO testimonies, numerous Wall Street equity research analysts published their reactions. In simple words, their universal reaction has been shock and disbelief.

Steve Fleishman of Merrill Lynch, one of the most respected and highly-rated utility equity analysts on Wall Street, wrote:

> The recommendation took an **extreme negative position** on essentially every count.
>
> Staff's recommendation is obviously very disappointing.
>
> … we believe **staff's positions are so extreme** and they are not likely in our view, likely (sic) to be adopted in the final order. For example, **the 9% ROE would be the lowest we have ever seen allowed by any state**, let alone one like Arizona where rapid growth requires significant future capital investment. Moreover, the decision on the PWEC assets does not seem to account for the long-term customer needs for this power, particularly for the West Phoenix plants that are in the Phoenix load pocket. (emphasis added)

Dan Eggers, Credit Suisse First Boston's senior utility equity research analyst wrote:

> The 9% ROE recommendation appears low considering recent rate case decisions in Arizona (11%) and around the country. A lower interest rate environment can be argued for a rate below the requested 11.5%, but the proposed rate seems extreme considering PNW's solid reliability record, market growth, and low customer rates relative to history.

Jim von Riesemann, J.P. Morgan Securities' equity research analyst wrote:

> … the ACC [staff] essentially denied all of APS' request and **set a more punitive return requirement than any other commission has implemented**. (emphasis added)

Kit Konolige, Morgan Stanley's equity research analyst wrote:

> The staff also proposed a very low 9% ROE, about **the lowest we have seen even** in a recommendation…. (emphasis added)

Q. HAVE THE STAFF RECOMMENDATIONS BEEN REFERENCED IN EQUITY RESEARCH ANALYST REPORTS ON OTHER COMPANIES?

A. Yes, a Lehman Brothers equity research report dated February 18, 2004 regarding Edison International, authored by Daniel Ford, a well–respected and well-read analyst, added the following title to the report:

> **ALJ Rec Disappointing but not Arizona**

I can understand a reader's reaction to this title could range from "cute," to "overreaching," to "inappropriate," to "a point well made." Regardless, this title, when taken with the other comments from analysts, provides clear evidence that Wall Street has associated Staff's recommendations with the very lowest and most extreme of regulatory policy. Such an association, if allowed to perpetuate, will be a substantial detriment to the future of APS, our customers, and Arizona.

Another Lehman Brothers equity research report dated March 5, 2004, also authored by Mr. Ford, titled "*They're Back! Twenty-Six Rate Cases This Year Give Rise to the Regulators*," contained a ranking of 48 state utility commissions from an investor perspective. The report stated that the rankings were based on six criteria: 1) elected versus appointed commissions; 2) performance based rate mechanism or not; 3) allowed ROEs; 4) tendency to settle vs. litigate rate cases; 5) rate levels; and 6) a subjective investor friendliness rating which they defined as "a track record for reaching decisions that are outside of consensus expectation, staff reputation and influence, and ability to recognize and address emerging trends are some key considerations." In their ranking, the Arizona Corporation Commission was ranked 45th, in a three-way tie with the New Hampshire and New Mexico commissions, and just above the bottom-ranked Nevada Public Utilities Commission.

Q. SHOULD THIS COMMISSION CARE WHAT LEHMAN BROTHERS, DANIEL FORD, OTHER EQUITY ANALYSTS, OR ANYONE ELSE ON WALL STREET THINKS ABOUT ARIZONA REGULATION?

A. Yes. This Commission has to care what Wall Street thinks. Wall Street will be the source of the capital that will allow APS to grow to meet the energy needs of our customers. In all likelihood, over the long term, APS will obtain the capital it needs to grow. The question is "at what cost." What Wall Street thinks of APS and this Commission will have a great bearing on the ultimate cost that is charged to our customers.

I do not believe that "pro-investor" and "pro-consumer" attitudes or actions are incompatible. Achieving the label of "pro-consumer" in the eyes of Wall Street might come at a horrific cost to Arizona customers. As I mentioned earlier, I have worked in the finance function of utilities for many years. Few people know better than I the frustrations and outright annoyance at the changing whims and recommendations of Wall Street analysts. As difficult as it may be at times, we have to put ourselves above that rhetoric and focus on what is important and what doesn't waiver: Wall Street is the source of capital in this country. That capital will be allocated and priced based on risk. Injecting added risk, be it in the form of inconsistent regulatory policy, punitive ROEs, eliminating fuel and purchased power clauses, or other matters at issue in this case, will result in Wall Street extracting a punishingly-high cost from our customers.

I am very concerned about the negative image for Arizona that has been created by the Staff and RUCO recommendations. Never before have I seen such a backlash from Wall Street. Yes, analysts will typically use terms such as "pro–consumer," "consumer friendly," and "below consensus estimate" to describe a regulatory situation that does not meet their ideal. But I do not recall another situation where the tone of their reaction was set with terms such as "extreme negative," "so extreme," "lowest we have ever seen," "punitive return," "staff has no understanding," "lowest ROE authorized any major utility in at least the last 15 years," "punitive and irresponsible," "abysmal returns," "shocking," and "unbelievable." The citizens of Arizona can not afford to have this image perpetuate itself—the long-term costs will be too great.

APS serves the electricity needs of much of the growing state of Arizona. Economic growth and development in the state relies on a number of factors. As discussed by APS witness Alan Maguire, reliable electric service is a primary ingredient to the continued healthy economic climate of the state. Customers expect reliable electric service and that requires APS to continue to invest in generation, transmission and distribution plant to meet the needs of the ever-growing customer base. APS needs to be able to access the capital and bank markets at reasonable price levels and terms to be able to fund its growing infrastructure. Non-investment grade, "junk" credit ratings will eliminate the Company's ability to attract capital at a reasonable cost.

In addition, an adverse decision in this proceeding would tarnish other entities regulated by the Commission. Regulatory climate is a key component to attracting capital at a reasonable cost. If the Commission wishes to foster the healthy economic environment that Arizona currently enjoys, it should reject Staff and RUCO's recommendations.

Q. HAVE ANY OF PINNACLE WEST'S INSTITUTIONAL SHAREHOLDERS REACTED TO THE STAFF'S TESTIMONY?

A. Wellington Management Company owns approximately 11 million shares, or about 12% of Pinnacle West. Mark Beckwith, a senior vice president at Wellington wrote:

> I think it's fair to say that no recovery on the gas assets, a 9% ROE, no fuel and purchased power clause, and no reversal of the disallowance shows that the **staff has no understanding of risk/reward for capital investment**. (emphasis added)

JP Morgan Fleming Asset Management owns approximately 9 million shares, or about 9.8% of Pinnacle West. Terry Shu, a managing director at that firm, in a telephone conference that included three JP Morgan portfolio analysts in New York and Bill Post, Jack Davis, and me in Phoenix, described the Staff's recommendations as **"shocking," "unbelievable,"** and **"contrary to the positive business climate in Arizona,"** and concluded that, if implemented, the Staff's recommendations would result in **"abysmal returns."**

Q. ARE YOU FAMILIAR WITH THE FIRM, REGULATORY RESEARCH ASSOCIATES, INC.?

A. Yes, Regulatory Research Associates (RRA) is a well-known and respected independent research organization that provides research regarding public utility regulation.

Q. DID RRA HAVE A REACTION TO THE STAFF AND RUCO TESTIMONIES?

A. Yes, on February 6, 2004, RRA published an update that addressed the Staff and RUCO testimonies. The RRA update included the following comment:

> We note that the 9% ROE recommended by the Staff is well below the average equity return authorized energy utilities nationwide during 2003, and would be, to our knowledge, **the lowest ROE authorized any major utility in at least the last 15 years.** While

> the average of authorized ROEs has trended down slightly in the last year or so, especially for lower risk utilities that are primarily energy deliverers, we note that APS is a vertically integrated utility operating in a high growth territory that is forecast to be capacity short in just a few years. Additionally, the company continues to be exposed to variations in fuel and purchased power costs in an environment in which it must purchase a significant portion of its energy needs (and the Staff is recommending against implementation of a fuel and purchased power adjustment mechanism). (emphasis added)

Q. DID YOU RECEIVE ANY REACTION FROM THE DEBT CAPITAL MARKETS REGARDING THE STAFF AND RUCO TESTIMONIES?

A. Yes, on the morning after Staff and RUCO filed their testimonies, William Rogers, a managing director on the Merrill Lynch debt capital markets desk wrote:

> APS credit spreads are 10 bps wider [more expensive] after yesterday's **<u>punitive and irresponsible announcements</u>**. (emphasis added)

Q. HOW HAS PINNACLE WEST STOCK PERFORMED SINCE THE STAFF AND RUCO FILED THEIR RECOMMENDATIONS ON FEBRUARY 3?

A. Pinnacle West stock has significantly underperformed U.S. electric utilities, as measured by the S&P 500 Electric Utility Index. Pinnacle West stock underperformed the index by approximately 3% (sometimes more) since February 3, 2004. As a result of this underperformance, Pinnacle West shareholders have lost $100 million of their value.

Q. GIVEN THE DRACONIAN FINANCIAL CONSEQUENCES THAT YOU FORECAST WOULD OCCUR IF THE STAFF OR RUCO RECOMMENDATIONS WERE ADOPTED, CAN YOU EXPLAIN WHY THE STOCK MARKET REACTION HAS NOT BEEN MORE NEGATIVE THAN A 3% RELATIVE UNDERPERFORMANCE?

A. Yes, I can. The stock market reflects risk-adjusted investor expectations. Investors believe that the actual Commission order in this case will be supportive of APS. Clearly, the Staff and RUCO recommendations added an additional element of downside risk to the investors' valuation of Pinnacle West stock – and that negative risk is evident in the 3% underperformance. Investors' expectations are echoed by the following:

S&P on March 19, 2004 wrote:

> ...Standard & Poors expects that the commission will act prudently to provide APS with a reasonable rate increase...

Merrill Lynch's Steven Fleishman wrote:

> ...we believe staff's positions are so extreme and they are not likely in our view, likely (sic) to be adopted in the formal order.

Deutsche Bank's equity research analyst James Dobson wrote:

> It is important to remember that Staff's position is just a recommendation at this point, and it is likely that the final outcome from the ACC will be quite different (read that as BETTER).

And Credit Suisse First Boston's Dan Eggers wrote:

> With a growing generation shortfall in PNW's service territory owing to the market's strong underlying demand growth, inclusion of these assets in rate base makes good long-term economic sense.

The financial community, while shocked by the extreme nature of the Staff and RUCO recommendations, has dismissed them as highly unlikely outcomes of this case.

Q. DOES PINNACLE WEST HAVE SHAREHOLDERS IN ARIZONA WHO WOULD BE IMPACTED ADVERSELY IF STAFF'S OR RUCO'S RECOMMENDATIONS WERE ADOPTED?

A. Yes. Our shareholder services department maintains 16,633 Pinnacle West shareholder accounts identifiable to Arizona residents. These accounts represent about 5.2 million shares, or about 6% of Pinnacle West's stock. We are unable to identify the additional number of individual Arizona residents who hold shares through brokerage firms or other nominees. Many others, no doubt, are indirect owners of Pinnacle West stock through mutual funds, pension funds, etc. Referring to the $100 million loss of Pinnacle West stock value noted above, about $6 million of that loss was suffered just by the identifiable 16,633 Arizona resident's accounts.

VI. PRELIMINARY INQUIRY

Q. ARE YOU FAMILIAR WITH THE PRELIMINARY INQUIRY THAT RESULTED FROM THE FINANCING APPLICATION?

A. Yes. I have read Decision No. 65796 (April 4, 2003) directing the Staff to conduct the inquiry and the report issued by the Company on June 13, 2003 regarding the issues addressed in the inquiry.

Q. HAVE YOU READ THE RATE CASE TESTIMONY FILED ON BEHALF OF STAFF BY MS. JARESS AND, IN PARTICULAR, THE PORTION OF HER TESTIMONY DEALING WITH THE INQUIRY DISCUSSED ABOVE?

A. Yes, I have, and it appears that she has a misunderstanding of the process companies go through in obtaining contingent bond ratings, as well as what a contingent rating means and does not mean. Her testimony also contains some factual errors that I'd like to correct.

Q. IN YOUR YEARS AS AN ELECTRIC UTILITY FINANCIAL EXECUTIVE, HAVE YOU HAD EXPERIENCE WORKING WITH THE CREDIT RATING AGENCIES?

A. Yes, as an officer of a rated company, I have worked with S&P and Moody's for more than 20 years.

Q. DO YOU HAVE ANY EXPERIENCE IN OBTAINING CREDIT RATINGS FOR AN ELECTRIC GENERATING COMPANY AFFILIATED WITH A REGULATED UTILITY, SIMILAR TO THE SITUATION THAT EXISTED WITH APS AND PWEC?

A. Yes, I have experience with a situation that is very similar.

In 2000, in my capacity as Ameren Corporation's chief financial officer, I had primary responsibility for obtaining the initial financing for AmerenEnergy Generating Company, including development of the business financial model and obtaining credit ratings from S&P and Moody's.

Ameren's regulated utility subsidiary, Central Illinois Public Service ("CIPS") provides electric and gas service in the southern two-thirds of the State of Illinois. As permitted by the Illinois Electric Service Customer Choice and Rate Relief Law of 1997, on May 1, 2000, CIPS transferred all 2,860 megawatts of its regulated electric generating assets, at historical net book value, to a newly created non-regulated Ameren affiliate, AmerenEnergy Generating Company ("Genco"). The transferred assets were primarily base load, coal-fired units. Effective with the transfer of the generating assets, Genco had a power supply agreement to supply the power required for: (1) CIPS' retail native load requirements and (2) CIPS' long-term contracts. This contract had a term of 56 months with an expiration date of December 31, 2004.

The Genco business plan provided for the growth of the Genco generation capacity to 4,675 megawatts as of December 31, 2002. The newly added 1,815 megawatts of generating capacity consisted of gas-fired combustion turbine generating units and gas-fired combined cycle generating units. The construction of the new generating capacity required an initial debt financing of $425 million on November 1, 2000.

In preparation for the debt financing, we prepared a long-term financial model based on: (1) operating expense forecasts, (2) capital addition plans, (3) electric sales and revenue forecasts, and (4) unit dispatch and fuel price forecasts. Our electric sales and revenue forecasts were based on our independent market consultant's, Resource Data International, Inc. ("RDI"), analysis of the Midwest electricity market and the economic competitiveness of Genco's generating facilities within that market. Stone & Webster Consultants, Inc. ("S&W") had prepared an independent technical review of Genco's generating facilities.

I had numerous meetings with representatives of Moody's and S&P during 2000 to review our financial model, along with the RDI and S&W reports. On November 1, 2000, we sold $425 million of debt securities consisting of $225 million of 7.75% Senior Notes, Series A due 2005, and $200 million of 8.35% Senior Notes, Series B due 2010. The Series A Notes were rated A3 by Moody's and BBB+ by S&P. The Series B Notes were rated Baa2 by Moody's and BBB+ by S&P.

Q. WHAT WERE THE MAJOR FACTORS THAT MOODY'S AND S&P CONSIDERED IN DETERMINING THE CREDIT RATINGS ON THE AMEREN GENCO NOTES?

A. The primary factors were the Genco's low-cost generating asset portfolio, solid financial projections, Ameren's knowledge of the generating assets and the regional power markets, and strong transmission ties.

Q. HOW MUCH OF A FACTOR WAS THE GENCO'S POWER SUPPLY AGREEMENT IN DETERMINING THE CREDIT RATINGS ASSIGNED BY THE MOODY'S AND S&P?

A. The existence of the power supply contract was a factor for the relatively short-term 5-year Series A Notes, but not a substantial factor relative to the 10-year Series B Notes.

First, the term of the power supply contract was only 56 months, whereas the debt had a weighted-average life of more than 88 months. In the instance of the Series B Notes with a 10-year term, the Series B Note investors would have reasonably expected that the power supply agreement would have been long expired before the notes matured. Accordingly, the investors would not have placed significant reliance upon the cash flows derived from the power supply agreement.

Second, at the time the credit ratings were issued, the market price of power was higher than the cost-based pricing structure inherent in the power supply agreement. Thus, providing power under the power supply agreement was a negative due to the lost opportunity to sell that power to the market at a higher price.

Of the two agencies, Moody's gave greater consideration to the existence of the contract. That consideration is evidenced by the "split" rating given by Moody's: the Series A Notes, with a maturity of 5 years, received the higher "A3" rating, whereas the Series B Notes, with a maturity of 10 years, received the lower "Baa2" rating. This was Moody's way of recognizing that the power supply agreement provided some degree of certainty to cash flows relative to the 5-year notes, but not much, if any, certainty to cash flows relative to the 10-year notes.

Q. PLEASE EXPLAIN WHAT A CONTINGENT CREDIT RATING IS.

A. A contingent credit rating is a rating assigned by a credit rating agency to a given hypothetical situation. The term "contingent" is the key descriptor in that it identifies the fact that the rating is not yet active and not available for use in issuing debt securities, but it is contingent on certain events occurring and the company obtaining an actual credit rating on which debt could be issued.

As Mr. Fetter explains in his rebuttal testimony, business entities in many sectors, including the utility industry, at times seek guidance in the form of contingent credit ratings from the credit rating agencies in advance of taking a major strategic step, such as a merger or restructuring. The guidance provided by contingent credit ratings would allow an entity to alter its business model or strategy to adjust its credit metrics to achieve a more acceptable result.

Q. COULD A COMPANY ISSUE DEBT SECURITIES WITH A CONTINGENT CREDIT RATING?

A. No.

Q. COULD YOU EXPLAIN THE PROCESS OF OBTAINING A CREDIT RATING?

A. Yes. The process begins with the development of a business model that takes a number of factors into account, including, in the case of power plants, heat rates, forecasted gas costs and electricity prices, forecasted sales volume and regulatory environment. Engineering consultants are engaged to perform the technical analysis on the plant output and market analysts are engaged to forecast prices and demand. Cashflow forecasts are developed using the forecasted operating costs and revenue. These forecasts are then stress-tested for sensitivity to major inputs, such as spark spreads and sales volume. Once the model is completed, it is presented to the rating agencies. The agencies then take various engineering, cost and revenue assumptions and develop their own model to evaluate the creditworthiness of the entity. They also perform stress tests on the assumptions to develop their own conclusions. For example, if a company had modeled in a scenario in which it had contracted for the total output of a plant, the agencies would stress test that assumption by possibly factoring down the contracted output all the way to zero, forcing the results to be driven purely by forward spot prices. They arrive at what they view as a reasonable scenario and rate the entity accordingly.

Q. COULD YOU EXPLAIN THE PROCESS AS IT SPECIFICALLY RELATES TO PWEC'S CONTINGENT RATINGS?

A. In the case of PWEC's contingent ratings, the process was described in APS' June 13, 2003 Report to the Commission. The following excerpt from pages 55-57 of that report describes the process PWEC followed:

> In preparing the rating agency presentation for PWEC's initial credit ratings, Pinnacle West and PWEC followed standard industry practices. This included the hiring of independent market consultants (PA Consulting) and independent engineers (Stone and Webster). The two parties were hired in August 2000 and worked for approximately six months developing market forecasts (PA Consulting) and performing in-depth reviews of all of the power plants.
>
> The presentation book given to the rating agencies reflected the PA Consulting and Stone and Webster forecasts, as well as Pinnacle West's assumptions including:
>
> - the transfer to PWEC of APS' fossil generation assets in January of 2001 and APS nuclear generation assets by the end of 2002;
>
> - PWEC generation additions of Redhawk units 1, 2, 3, and 4 (2,026 MW total), West Phoenix units 4 and 5 (631 MW total), and the purchase of 72 MW from Nevada Power Company at the Harry Allen plant in Nevada;
>
> - that, post-divestiture, PWEC generation would be dedicated to native load requirements through a transfer pricing agreement ending in 2004 in conformance with Rule 1606(B) or, if deemed necessary, a variance to that rule.
>
> Given the circumstances at the time, Pinnacle West believed these all to be reasonable assumptions. However, it is clearly the last assumption that has caused the most confusion in Decision No. 65796.
>
> As noted above, there was an assumption made for purposes of financial modeling that a purchase power agreement would be used to serve APS' needs through 2004. Under this assumption, for 2001 and 2002, PWEC would supply that generation through a contract with Pinnacle West Marketing and Trading, which in turn would resell the power to APS at a market price. This period was prior to when the competitive bidding requirement in Rule 1606(B) would

become effective. For 2003 and 2004, the assumption was that PWEC would continue to sell all of its power to Pinnacle West Marketing and Trading. Pinnacle West Marketing and Trading would provide power to APS at market prices but up to 50 percent of APS' power could be supplied through the competitive bidding process in the Electric Competition Rules.[4]

Thus, under this model, PWEC would sell *all* of its power to Pinnacle West Marketing and Trading and APS would procure *all* of its needs at market prices, including the possibility of 50 percent coming through competitive bidding.[5] It was reasonable to assume that a significant amount of APS' power would be supplied by the fuel-diverse fleet of generation that was being divested by APS pursuant to the Electric Competition Rules. Also, there was no reason for APS to believe that a contract at market prices would not have been considered an "arm's length" transaction. There was, however, never a representation made to the rating agencies that PWEC actually had a signed contract with APS through 2004, or that APS would contract with PWEC in some manner that violated the Electric Competition Rules. Neither was there any representation made that the Commission had approved such an agreement.

Executives from Pinnacle West met with the rating agencies to review the presentation book. After the initial meeting, each of the rating agencies followed up with requests for various scenarios "stress testing" the forecasts. Each of the three agencies used its own assumptions in addition to those modeled by PA Consulting, Stone and Webster, and Pinnacle West. Had the rating agencies felt that any of the assumptions were unrealistic, they presumably would have modeled it differently and the financial modeling was, after all, ultimately their responsibility. And, the rating agencies were specifically provided with copies of the Electric Competition Rules and the 1999 Settlement.

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[4] *See. e.g.*, PWEC Rating Agency Presentation (February 2001) at p. 12 (specifically referring to the 50 percent competitive bidding requirement in the Electric Competition Rules). This presentation was Panda-TECO Exhibit No. 23 in the proceeding on the Financing Application.

[5] The full output contract between PWEC and Pinnacle West Marketing and Trading for the PWEC generation would have remained in effect regardless of whether APS was being supplied by other parties under the competitive bidding requirement in the Electric Competition Rules.

After their analysis, contingent investment grade credit ratings were deemed appropriate by each of the rating agencies based on credit metrics for a 20-year horizon. The agencies looked at the minimum fixed charge coverage ratio ("FCCR") as well as the average over that 20-year period. They looked at the FCCRs in the base case that was presented as well as the various stress scenarios. Even had the purchase power agreement modeled in the base case been above or below market, because of its relatively short term of four years, it would have had a minimal impact in evaluating the entire 20-year horizon studied by the agencies.

Later in 2001, the electric utility industry started to experience the difficulties centered around Enron and other merchant generating companies. The bank and debt capital markets became extremely sensitive to any complication in a company's credit picture. Pinnacle West's bankers had been kept apprised of the planned divestiture of the APS generation and the then-planned phased-in approach of first transferring the fossil units and then the nuclear units by the end of 2002. Pinnacle West realized in the fall of 2001 that a transfer of the fossil assets might not occur that year given the recent crisis in California. However, by this time, project financing options were no longer available for Pinnacle West or PWEC, just as they were not for the vast majority of the industry. The Commission initiated its inquiry into the Electric Competition Rules in 2002 and halted the planned divestiture of the APS generation to PWEC, thus rendering the contingent credit ratings moot.

Q. WHAT WERE THE KEY MESSAGES THAT PINNACLE WEST FOCUSED ON WHEN MAKING THE PRESENTATIONS TO THE RATING AGENCIES?

A. There were four primary long-term fundamental strengths that Pinnacle West emphasized. First was that PWEC (which was presumed to include the APS generating assets as ordered by the Commission) would be selling power into a growing market. Second, the generating assets owned by PWEC were high quality and low cost. Specifically, the APS assets had an excellent track record in terms of operations and were well positioned on the dispatch curve. Third, the generating asset portfolio was diverse because it would consist of a good blend of nuclear, coal and gas fired generation. The balanced fuel mix and the fact that no one unit comprised more than 15% of cash flows led to reduced financial risks. And finally, the resulting coverages based on the modeling assumptions were strong. The 20-year average fixed charge coverage ratio based on anticipated market prices was a strong 7.5 times.

Q. WHAT ROLE DID THE PPA ASSUMPTION HAVE ON THE CONTINGENT CREDIT RATINGS?

A. One of the many assumptions that Pinnacle West shared with the agencies was that they had factored in an assumed short-term PPA between PWEC, Pinnacle West and APS. It was only a 4-year assumed contract in a 20-year planning model so the agencies would not have placed much, if any, weight on this one assumption as compared to the other long-term fundamental strengths noted above.

Q. WHAT WAS THE IMPACT ON APS OF THIS ASSUMPTION REGARDING THE PPA?

A. Given the soaring price of power in late 2000 and early 2001, when the agencies were developing their contingent ratings for PWEC, the PPA was likely viewed as a positive factor more for APS than PWEC. That is because APS would be divesting all of its generating assets and therefore be exposed to increasing prices through 2004 if not for the PPA assumption. Since no debt was ever issued, there was no actual impact on APS or PWEC.

Q. WAS THE PWEC CONTINGENT CREDIT RATING PROCESS DIFFERENT FROM OTHER GENCO RATINGS AT THAT TIME?

A. In some respects, yes. Although the process followed was identical to that used by the other utilities that formed Gencos, the fact that PWEC was not imminently ready to issue debt was unusual. Typically, Gencos go through this credit rating process with the intent of obtaining a credit rating relative to a specific debt issuance. They follow a process as I described above. The rating agencies typically issue credit ratings within just a few weeks, if not days, of the actual debt issuance.

PWEC was different in that PWEC management had no intent of issuing debt until the APS generating assets transferred, which would not happen until sometime in the future.

Q. WHY DID PWEC WANT TO OBTAIN CONTINGENT CREDIT RATINGS GIVEN THAT THE DEBT ISSUANCE WOULD BE SO FAR INTO THE FUTURE?

A. As explained by APS witness Jack Davis, management was being conservative in that they wanted assurance that under the proposed PWEC business model, the credit ratings would be investment grade. If the contingent credit ratings had come back as non-investment grade, management would have had an opportunity to modify the PWEC business model so as to achieve the requisite credit profile to obtain investment grade credit ratings. In simple terms, management wanted assurance that it was not about to transfer Palo Verde, Cholla, Four Corners, and other APS generating assets into an entity whose only financing option was limited to issuing "junk" bonds.

Q. PLEASE DESCRIBE THE ASSUMPTIONS PROVIDED REGARDING THE PWEC FUTURE FINANCINGS WHEN PINNACLE WEST MADE THE PRESENTATIONS TO THE RATING AGENCIES.

A. Although PWEC had no intention of issuing debt in the near future, PWEC made assumptions based on reasonable expectations of the future financings. PWEC assumed a $500 million bank credit facility would be established with a bank group at a 7% interest rate. Borrowings under the credit facility would fund the PWEC gas-fired generation construction. It was assumed that in 2003, $300 million of bank borrowings would be repaid by issuing 8.2% Senior Notes with a 7-year maturity. It was further assumed that in 2010, the remaining bank borrowings and the 7-year Senior Notes would be repaid by issuing amortizing Senior Notes with an average life of 28 years and a weighted average interest rate of 6.85%. It was also assumed that $656 million of APS tax-exempt debt would transfer to PWEC along with the power plants and their associated pollution control equipment.

Q. WHAT IS THE SIGNIFICANCE OF THIS FINANCING PLAN IN RELATION TO THE ASSUMED PPA?

A. From the long-dated term of the debt assumed in the financing plan, it is obvious the rating agencies needed to assign the contingent credit rating based on the long-term cash flows of PWEC. The assumed short-term PPA would have been largely immaterial in supporting the financing needs of PWEC because it was assumed to have such a short-term – effectively less than 4 years as compared to the almost 40-year financing plan.

Q. AFTER THE RATINGS HAVE BEEN ISSUED, HOW DOES THE PROCESS RELATED TO A CONTINGENT CREDIT RATING DIFFER FROM A "NORMAL" CREDIT RATING?

A. There is a significant difference. After a company obtains "normal" credit ratings, they are under the constant surveillance of the rating agencies. At a minimum, the rating agencies do a detailed annual review and write-up on the company. The qualitative and quantitative aspects of the company are analyzed in detail. In addition, the rating agencies follow all developments of a company by following all materials written about the company. There are frequent conversations between the agencies and, typically, the company's Treasurer and Chief Financial Officer. Based on developing information, the rating agencies may upgrade or downgrade a company's ratings or put them on outlook or watch list, which indicate potential movements in ratings in the near future. In contrast, after a contingent credit rating is issued there is no additional monitoring or dialogue by the agencies. Because the ratings cannot be used to issue debt, there is no reason for the agencies to follow the situation and assumptions that were initially presented. Instead, they wait until the company returns for actual ratings to do any further analysis. In simple terms, a contingent credit rating is nothing more than a one-time academic study of a set of hypothetical assumptions.

Q. WHAT ERRORS IN MS. JARESS' TESTIMONY WOULD YOU LIKE TO CORRECT?

A. On page 12 at line 31 of her testimony, Ms. Jaress refers to concerns over how PWEC was able to obtain an investment grade rating from credit rating agencies in early 2001 <u>when it was seeking to acquire long-term financing to construct generating plants.</u> In fact, PWEC never was able to even seek to acquire long-term financing because its ratings never became effective. The ratings received from the agencies were contingent upon the transfer of the APS assets into PWEC and would only become effective after the transfer occurred and all of the other key assumptions were confirmed. Before the rating agencies would ever issue "normal" credit ratings that could be utilized to access the capital markets, all of the assumptions utilized during the process of obtaining the contingent ratings would have been revisited and confirmed by the rating agencies. For example, the ratings agencies would have required executed copies of any key contracts, including a PPA. They also would have required proof that the PPA had received all necessary regulatory approvals from all relevant jurisdictions. In addition, the debt underwriters involved in marketing the debt would have required the same level of assurance in performing their due diligence associated with underwriting the securities.

Q. MS. JARESS STATES THAT PRESENTING THE PPA AS A FULL-REQUIREMENTS CONTRACT TO THE RATING AGENCIES GAVE PWEC AN UNFAIR ADVANTAGE BECAUSE THE RATING AGENCIES WOULD VIEW THE ARIZONA MARKET AS RISKIER FOR THE MERCHANT GENERATORS, RESULTING IN WEAKER RATINGS. IN YOUR EXPERIENCE, HAVE YOU EVER KNOWN RATING AGENCIES TO USE INFORMATION OBTAINED FROM ONE COMPANY TO THE DETRIMENT OF ANOTHER?

A. No, I have not. And, as Mr. Davis testifies in his rebuttal testimony, there was never even a draft of a "full-requirements" contract between APS and PWEC presented to the rating agencies. There was a draft "full output" contract between PWEC and Pinnacle West. A draft APS/Pinnacle West contract did give APS a full "call" on PWEC's generation resources at market price, but also permitted APS to obtain some or all of its generation resources elsewhere – the antithesis of a "full-requirements" contract. That being said, it would be completely irrational to rely upon information provided by one entity to develop any insight or opinions regarding another entity. In addition, any entity, including the merchant generators, would have been free to present its own scenarios to the agencies for their consideration. There is simply no factual support for Staff's underlying assumption that a PWEC PPA would alter the risk profile of any unidentified "merchant generator."

Q. WOULD THE RATING AGENCIES HAVE TAKEN THE PPA AT FACE VALUE OR SIMPLY USED IT IN MODELING VARIOUS SCENARIOES AS PART OF THEIR EVALUATION?

A. As I described above, the rating agencies would have viewed any draft PPA as only one of the many assumptions used in the modeling process.

Q. DO YOU BELIEVE THERE WAS ANYTHING UNFAIR, DISHONEST, MISLEADING, UNETHICAL OR OTHERWISE INAPPROPRIATE ABOUT HOW PINNACLE WEST / PWEC / APS PRESENTED THE PPA IN THE PRESENTATIONS MADE TO THE RATING AGENCIES?

A. No, I do not. The process followed would be considered standard practice. It was comparable to the process I followed at Ameren and based on my numerous discussions with others in the industry, investment bankers and rating agencies, it was the process followed in the formation of most generating companies.

VII. CAPITAL STRUCTURE

Q. HAVE YOU REVIEWED THE RECOMMENDATIONS OF MR. REIKER AND OF RUCO WITNESS STEPHEN HILL REGARDING THE CAPITAL STRUCTURE OF THE COMPANY?

A. Yes, I have, and I disagree with both of their recommendations. APS' capital structure in the test year 2002 was 50% debt/50% equity. (*See* Mr. Robinson's Schedule D-1.) It is appropriate to maintain that 50%/50% capital structure if the PWEC dedicated units are not rate-based because that structure eliminates the $500 million of APS debt that was issued for the inter-company loan between APS and PWEC. When the Commission approved the issuance of this debt and the inter-company loan, it did so with the full understanding that the purpose of the funding was to refinance debt at Pinnacle West that had been issued to fund construction of the PWEC dedicated units. In fact, the Commission's order in that matter stated that the $500 million of additional debt was not to be included in the debt limit specified in the 1986 Financing Order. The $500 million debt amount is clearly not related to a utility asset unless and until the PWEC assets are acquired by APS to use in providing service to its customers, and accordingly should not be included in the capital structure of the Company if the dedicated units are not rate-based. In that instance, the debt amount is specifically tied to a non-regulated, non-APS asset, the capital costs of which should not be factored into the determination of APS capital costs to be passed on to APS customers.

Q. IS THERE ANOTHER REASON TO REVERT TO THE COMPANY'S ACTUAL END-OF-TEST PERIOD "50/50" CAPITAL STRUCTURE?

A. Yes. As I discussed earlier, S&P considers additional purchased power liabilities as equivalent to increased debt. If, without the rate-basing of the PWEC assets, APS had to acquire 1,700 MW plus of increased purchased power, APS would be treated for credit rating purposes as already having a more leveraged capital structure. I am told that $163 million in capacity charges would be a conservative estimate for such a 1,700 MW PPA. That translates into $74 million in additional "interest" under the S&P methodology, which is equivalent to an additional $742 million of APS debt. After reflecting the imputed debt in APS' capital structure, APS' equity ratio for credit rating purposes would be reduced by 7%, down to 43%. Even if S&P had not formalized its consideration of purchased power as being "debt-like," APS knows that increased market exposure increases business risk, thus necessitating an offsetting reduction in financial leverage. That is why APS indicated during discovery that when the APS/PWEC loan is repaid (as it would under the "no rate-basing" scenario), APS would likely pay down an equivalent amount of debt.

VIII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS TO YOUR REBUTTAL TESTIMONY?

A. Yes. The Company was both surprised and disappointed at the apparent lack of consideration given by Staff and RUCO to the catastrophic impacts that adoption of their recommendations would have on the Company's financial integrity. The adoption of Staff's or RUCO's recommendations would lead to a reduction in earnings so dramatic that not only would the Company lose access to the capital markets at reasonable prices, thereby facing a dire financial future, but long-term reliability and customer service would be put at risk. The ROE recommendations in particular, if adopted, would only allow APS what amounts to perhaps the lowest ROE in the country, a result completely out of sync with the high growth rate and anticipated capital expenditures that the Company faces over the next several years.

It also is time to put to rest the concerns raised about the contingent credit ratings obtained by Pinnacle West for PWEC. Not only did Pinnacle West pursue those ratings in compliance with the applicable rules and just as any other company would have done, but it also acted prudently in seeking those contingent credit ratings to prepare for the transfer of the APS generating assets to PWEC as was then required by the Commission. This issue should not be one that distracts the Commission from the critical issue of the Company's financial future.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

APS-4R

EXHIBIT

APS-4R

admitted

REBUTTAL TESTIMONY OF DONALD G. ROBINSON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

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REBUTTAL TESTIMONY OF DONALD G. ROBINSON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Donald G. Robinson. I am Vice President of Planning for Arizona Public Service Company ("APS" or "Company"). My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. ARE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS SET FORTH IN APPENDIX A TO YOUR DIRECT TESTIMONY?

A. For the most part, yes. However, late in 2003, I was named Vice President of Planning for APS. I have responsibility for Corporate Planning, Resource Planning, Budgets, Forecasts, Energy Risk Management and New Business Ventures.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will first testify to the overall impacts on the Company's financial results and projections should the Arizona Corporation Commission ("Commission") accept either the Utilities Division Staff ("Staff") or the Residential Utility Consumers Office ("RUCO") recommended adjustments to our test period revenue requirement. Second, I introduce and explain the Company's proposal regarding a power supply adjustment rate mechanism to recover fuel and purchased power costs. Third, I will address and respond to the numerous specific test period adjustments advocated by Staff, RUCO, and Arizonans for Electric Choice and Competition ("AECC"). As part of this rebuttal, I discuss APS' proposal to include three additional adjustments, which I originally referenced in my Direct Testimony but were not quantified in the original filing. Finally, I will answer portions of Commissioner Gleason's October 29, 2003 letter to the Company.

Q. WILL YOU BE DISCUSSING ALL OF THE ADJUSTMENTS RECOMMENDED BY STAFF AND INTERVENORS?

A. No. As shown on Schedule DGR-1RB, certain portions of my Direct Testimony will be adopted by other APS witnesses. The following APS witnesses will address in rebuttal the issues associated with these areas:

- Pete Ewen will adopt my Direct Testimony related to Normalizing Weather Conditions, Annualizing Customer Levels, and Fuel, Purchased Power and Off-System Sales.
- Chris Froggatt will adopt my Direct Testimony related to Property Taxes. Mr. Froggatt also will discuss the determination of cost of capital consistent with the Company's recommendations regarding return on equity, Donald Brandt's recommendation on capital structure and Staff's recommendations regarding net losses on reacquired debt and capitalized vehicle leases. While not adopting my Direct Testimony, Mr. Froggatt also will be the Company's primary witness on income tax-related issues.
- While not adopting any specific portion of my Direct Testimony on the following issues, Laura Rockenberger will address cash working capital requirements, and in conjunction with John Wiedmayer, depreciation and amortization. In addition, Dr. Ron White will discuss accruing for net salvage value as a component of depreciation rates. Ms. Rockenberger also will discuss Independent Spent Fuel Storage Installation ("ISFSI") and, in this case, will adopt my Direct Testimony related to that adjustment.
- Ed Fox will discuss proposals related to the Environmental Portfolio Standard ("EPS") and the Company's expenses related to what Staff has classified as "advertising" and, along with Tom Hines, will discuss the Company's proposal related to Demand Side Management ("DSM").
- Alan Propper will address allocation methodologies and, along with David Rumolo, rate design.
- Mr. Rumolo also will discuss Schedule 1 charges and the Company's proposed Plans for Administration for various surcharges.
- Mr. Brandt will be discussing the Company's capital structure.
- Thomas LaGuardia will discuss Staff witness Harold Judd's recommendations regarding the exclusion of certain assets from decommissioning expense.

- Steve Wheeler will address the Company's opposition to proposals related to elimination of the 1999 APS Settlement write-off reversal.

My rebuttal testimony will discuss the balance of Staff's, RUCO's and AECC's adjustments.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. Yes. The recommendations of Staff and RUCO in the proceeding are extreme and, if adopted by this Commission, would crêate disastrous financial results. Both of those parties recommend a return on equity well below the average of equity returns found appropriate throughout the country. In fact, the Staff recommendation is the absolute lowest. How this is justified when one considers the level of growth and capital expenditures the Company faces defies logic. Furthermore, neither Staff nor RUCO conducted any credible financial analysis on the effects of their recommendations. Had they done so, they would have found that their recommendations produced returns on equity ("ROE") that are approximately 60% of the already confiscatory ROE recommended by their witnesses. APS witnesses Donald Brandt, the Company's CFO, and Steve Fetter, a former utility regulator and ratings agency executive, discuss the impact on the Company's financial health in much greater depth.

The Company also has proposed a modified Power Supply Adjustment mechanism to recover both purchased power and fuel costs. As a result of the Track A Order, the Company will continue to own and operate power plants. This coupled with the obvious reluctance of the merchant power plants to take the risk associated with the volatility of gas prices make the inclusion of fuel in this mechanism essential. Fuel and purchased power will make up almost half of the total Company expenses in 2005. This increased exposure to forward gas and power prices, coupled with price volatility of around 15% observed since 2001, further highlights the need to provide for the timely recovery of these expenses. Mr. Ewen provides further elaboration on the volatility of the purchased power and natural gas markets.

We have proposed two significant adjustments to the mechanism approved in Decision No. 66567 (November 18, 2003). First, we propose the inclusion of fuel primarily for the reasons I previously stated. Second, the Company has proposed a risk/benefit sharing mechanism whereby the Company and customers share in costs/savings on a 90% customer/10% APS basis. The Company also has proposed a $20 million "cap" on its share of costs/savings. This proposal allows the Company to recover the vast majority of its prudently incurred fuel and purchased power costs while providing an additional incentive.

My rebuttal testimony also discusses the additional modified adjustments. Each was mentioned in my Direct Testimony.

First, we have made an adjustment to include the replacement of the Palo Verde 2 steam generator. In our original filing, we included the fuel and purchased power savings associated with this replacement. Now that the costs are known, it is appropriate to include the steam generator replacement costs to properly match savings and costs.

Second, we have had to modify the expectations in our original filing of natural gas prices trending lower because just the opposite has happened. Moreover, the Company has updated fuel and purchased power costs to appropriately reflect current conditions.

Third, an adjustment has been made to reflect the costs associated with the bark beetle infestation. Because there is a slight potential for receiving partial reimbursement for these expenditures, we have proposed handling them through the System Benefits Adjustment Clause.

My testimony then discusses the rate base and operating income adjustments proposed by other parties. These adjustments fall into these categories: recommendations we do not oppose; those we can support in part; and those we completely oppose.

Finally, my testimony contains a response to a portion of Commissioner Gleason's October 29, 2003 letter.

III. FINANCIAL IMPACTS RESULTING FROM STAFF AND RUCO PROPOSED ADJUSTMENTS

Q. HAVE YOU FORECASTED THE IMPACT ON APS' FINANCIAL RESULTS IF STAFF'S OR RUCO'S RECOMMENDATIONS WERE TO BE ADOPTED BY THE COMMISSION?

A. Yes, I have. Both Staff and RUCO have recommended significant rate reductions that, if adopted by the Commission, would severely cripple the Company's financial health. As Mr. Brandt and Mr. Fetter testify, the Company would be downgraded to non-investment grade. At that point, the Company would be unable to access the capital markets on commercially-reasonable terms and may have no access under adverse market conditions such as prevailed as recently as 2002 and early 2003. This is an absolutely untenable position for any electric utility, let alone one with the second fastest growing service area in the United States. This growth requires substantial capital expenditures by the Company if it is to continue to provide reliable electric service.

The extreme nature of the Staff and RUCO positions is further highlighted by their recommendations that the Company should not receive an adjustment clause for fuel and purchased power expenses, a reversal of Staff's position of less than a year ago. This coupled with not rate-basing the PWEC dedicated assets adds significant risk and uncertainty to the Company's financial condition and further hurts the Company's credit rating. As Standard & Poor's ("S&P") stated in its January 29, 2004 research report, "A Fresh Look at U.S. Utility Regulation":

> [O]ne of the most important issues affecting ratings may or may not be part of the rate-case process, but is constantly tracked by Standard & Poor's: the recovery of fuel and purchased-power and gas costs. The analysis concentrates on stability of cash flows and the relative certainty of full recovery of these items, the largest expenses for almost all utilities, in arriving at a consensus on the level of a utility business risk.

Q. WHAT ARE THE FINANCIAL RESULTS FROM STAFF'S RECOMMENDATIONS?

A. On Schedule DGR-2RB, I have updated the relevant information using the same format as Schedule A-2 from the Company's original filing to reflect Staff's rate recommendations. The Company's net income under the Staff recommendation plummets almost 60% in 2005. As discussed more fully in Mr. Brandt's testimony, such a precipitous reduction in net earnings would have a disastrous impact on the Company's ability to access funds to undertake its planned infrastructure investments. The following summarizes the financial ratios that would result from Staff's recommendation:

- The Company's return on average common equity would be an anemic 5.5% in 2005.
- The Company's debt to capital ratio would rise to 61.6% in 2005.
- The funds from operations to average total debt ratio declines from 19.9% in 2003 to 12.2% in 2005.

- The pre-tax interest coverage ratio declines from 2.3x in 2003 to 1.8x in 2005.
- The funds from operation interest coverage ratio declines from 4.0x in 2003 to 2.8x in 2005.

As Mr. Brandt and Mr. Fetter testify, these 2005 indicators are all firmly in the non-investment grade level.

Q. DID STAFF PRESENT FINANCIAL IMPACTS WHICH RESULT FROM THEIR RECOMMENDATION?

A. No, they did not. The only mention of any financial indicator was a reference to a pre-tax interest coverage ratio by Staff witness Joel Reiker. That particular ratio was calculated incorrectly, however, as discussed in Mr. Brandt's testimony, and was not, in any event, an actual financial analysis but rather a simple mathematical tautology.

Q. DOES IT SURPRISE YOU THAT STAFF DID NOT TEST ITS RECOMMENDATION TO DETERMINE THE FINANCIAL IMPACT ON APS?

A. Yes, it does. I believe that Staff has an obligation to balance the interests of both the Company and its customers to ensure that both are treated fairly. I don't believe Staff's recommendation does this, nor could it without the sort of rigorous impact analysis discussed in my Rebuttal Testimony and that of other APS witnesses.

Q. WHY NOT?

A. Mr. Reiker recommends an already inadequate return on equity of 9%, but the Staff's overall recommendation actually produces a ROE of just 5.5% in 2005, approximately 61% of what even Staff determined to be fair. I have used 2005 results because with the current timing of the case, it is unlikely that new rate levels will be in place until the end of 2004.

Q. WHY DO YOU CONSIDER MR. REIKER'S 9% ROE TO BE SO INADEQUATE?

A. According to Regulatory Research Associates ("RRA"), Mr. Reiker's recommendation is lower than any granted ROE for at least the last 15 years in the United States for any major electric utility. *See* RRA, "Regulatory Update," February 6, 2004. The average ROE granted in 2003 was 10.97%, in 2002 it was 11.16%, and the average for the last 10 years was 11.28%. *See* RRA, "Major Rate Case Decisions—January 2002-December 2003 Supplemental Study," January 22, 2004. The average authorized ROE of those utilities found by Mr. Reiker to be "comparable" to APS is even higher – well over11%.

Mr. Reiker uses the current low level of interest rates as one reason his recommendation is reasonable. During 2003, however, when interest rates were just as low, the average ROE granted electric utilities nationally was 10.97%. In fact, in 2003 only five companies were granted ROEs less than 10%, only one as low as 9.5%, and all but one of these companies had fuel and purchased power mechanisms and/or other similar rate adjustment mechanisms, which lowers risk. Additionally, because none of those companies were located in states with growth rates approaching Arizona's, they do not have construction programs or capital requirements as large as APS.

Mr. Brandt, Mr. Fetter and Dr. Olson, and APS witnesses John Devlin and Dr. Thomas Zepp discuss Mr. Reiker's proposal in much greater depth. In more than twenty years of regulatory experience, however, I have never seen a Staff ROE proposal that is so clearly out of touch with the universal belief of other regulatory bodies throughout the United States as to what constitutes an appropriate ROE and which ignores key risk drivers like customer growth and fuel and purchased power price volatility.

Q. HAVE YOU FORECASTED APS' FINANCIAL RESULTS UNDER RUCO'S RECOMMENDATION?

A. Yes, I have. RUCO's recommendation produces results similar to Staff's, only not quite as severe. Like Staff, RUCO apparently made no serious attempt to test the effect of the recommendation and, as a result, the financial indicators are well below what they testify is appropriate.

Q. WHAT ARE THE FINANCIAL RESULTS FROM RUCO'S RECOMMENDATIONS?

A. Schedule DGR-2RB also includes the impact of RUCO's rate recommendations. The Company's net income under the RUCO recommendation falls by more than 45% in 2005. The financial results are as follows:

- The Company's return on average common equity would be just 6.7% in 2005. These results are well below the 9.5% found appropriate by RUCO witness Stephen Hill.
- The Company's debt to capital ratio would be 60.6% in 2005.
- The funds from operations to average total debt ratio declines to 13.9% in 2005.
- The pre-tax interest coverage ratio declines to 2.1x in 2005.
- The funds from operation interest coverage ratio declines to 3.1x in 2005.

Again, as Mr. Brandt and Mr. Fetter testify, these 2005 indicators also are in the non-investment grade level.

Q. HOW DID THE COMPANY FORECAST THE FINANCIAL RESULTS SHOWN ON SCHEDULE DGR-2RB?

A. The Company started with Schedule A-2, which is part of the Commission's standard filing requirements, and then made the necessary adjustments to reflect the Staff and RUCO recommendations.

Q. WHAT CHANGES DID YOU MAKE FOR THE STAFF AND RUCO RECOMMENDATIONS?

We reduced base revenues to reflect the elimination of the Company requested increase and to show the Staff or RUCO recommended decrease. Because of the recommendation to remove the PWEC dedicated assets from rate base, the operating costs for the assets were removed. This means that fuel and purchased power costs increased and off-system sales margins declined, however.

Consistent with the Staff recommendation, we lowered APS' annual depreciation and amortization expense, which will lower APS' cash flow. As discussed in more detail by Ms. Rockenberger, Dr. White and Mr. Weidmayer, depreciation is a current period non-cash expense that represents an annual recovery of a portion of the cash investment made in prior years to serve customers. By slowing down APS' recovery of depreciation and prior investments made to serve its customers, Staff's recommendation results in APS having less cash flow available to fund the capital expenditures required for system upgrades and maintenance critical to maintaining reliability. Lower depreciation recovery also will negatively impact the net cash flow measurements upon which bond rating agencies rely to determine whether the Company's bonds are investment grade.

To reflect the RUCO recommendation, an additional DSM adjustment was made. RUCO is recommending that APS be required to spend an additional $29 million per year on demand side management (DSM) expenditures. I have included the $29 million of annual revenues and $29 million of annual DSM expenditures on the income statement similar to the approach RUCO took in its pro forma adjustments. As this demonstrates, RUCO is, in fact, recommending an annual rate decrease on test year revenues of $82.6 million, because the Company's costs will increase by $29 million per year above what the Company requested. As Schedule DGR-2RB clearly demonstrates, the Staff and RUCO recommendations, if adopted, would put the Company into severe financial distress.

IV. APS' PROPOSAL ON A PSA MECHANISM

A. *Background and APS' Proposal.*

Q. IS THE COMPANY PROPOSING A MODIFIED POWER SUPPLY ADJUSTMENT MECHANISM IN RESPONSE TO STAFF'S RECOMMENDATION?

A. Yes. As I describe further below, APS is proposing a modified mechanism to recover both purchased power and fuel costs. I will refer to the proposed fuel and purchased power adjustment mechanism as a Power Supply Adjustor ("PSA").

As the Company explained in detail in its PSA proceeding (Docket No. E01345A-02-0403), APS is increasingly dependent on natural gas, both to run its own generating facilities and through its rapidly increasing dependence on purchased power, which is predominantly gas-fired. For example, in 1991 (the year following the Company's last full-blown general rate case), APS' purchased power accounted for approximately 6% of its energy needs and gas-fired generation accounted for only 3%. By 2005, the percentage of APS energy needs from gas and purchased power will have tripled to approximately 28%.

These two items alone (gas and purchased power) will constitute 56% of total fuel and purchased power expenses by 2005, the first full year for which the proposed PSA will be effective. And fuel and purchased power expense will have gone from constituting one third of all APS operating expenses in 1991 to almost one-half in 2005. At the same time that APS is becoming more dependent on natural gas and purchased power, prices for both have become more volatile. Both APS' increasing dependence on natural gas and the increasing volatility of natural gas prices clearly require the implementation of a PSA for APS.

Q. PLEASE DESCRIBE WHAT YOU MEAN BY INCREASING PRICE VOLATILITY IN NATURAL GAS AND PURCHASED POWER?

A. If one looks at the average natural gas price for delivery at the San Juan Basin or the SoCal Border, the volatility is evident. As discussed in detail in Mr. Ewen's testimony, the lowest price for San Juan Basin gas since 1998 was $1.00 per MMBTU and the highest price was $10.16 per MMBTU. The lowest natural gas price for the SoCal Border was $1.40 per MMBTU, while the highest price reached $59.42 per MMBTU during the same timeframe. Furthermore, Staff witness Douglas Smith in his testimony during this proceeding and graphically on Exhibit DCS-4, and Staff witness Barbara Keene in her Direct Testimony and Surrebuttal Testimony in Docket No. E-01345A-02-0403 (the "PSA Proceeding"), demonstrate the historical volatility in the natural gas market. *See* attached Schedule DGR-3RB. Finally, the existence and impact of the natural gas volatility has been well-described by several of the Commissioners in recent letters. (*See* Letter from Chairman Marc Spitzer, Docket No. E-01345A-03-0437, February 19, 2004; Letter from Commissioner Jeff Hatch-Miller to Senator John McCain, March 5, 2004). Mr. Ewen's testimony also discusses the volatility of power prices. He shows that in the three-year period 2001-2003, the price of on-peak power at Palo Verde ranged from a low of $15.50/MWh to a high of $537.02/MWh.

Q. DO THE RESPONSES RECEIVED BY APS TO ITS RFP FOR POWER SUPPLY RESOURCES PROVIDE ANY SUPPORT FOR THE IMPLEMENTATION OF A PSA?

A. Yes, they certainly do. A summary of the responses was filed by APS with the Commission on January 27, 2004. As reflected in that summary, nine entities responded to the RFP with thirteen different proposals. All of the entities that submitted bids were either merchant generators or power marketers. All of the asset-backed proposals involved natural gas-fired generation requiring APS and its customers to bear the fuel price risk in one form or another. All of the PPA bids required APS to accept the risk of natural gas price volatility. Several bidders offered tolling agreements whereby the bidder would procure the gas with APS paying an indexed gas price plus a mark-up percentage.

Q. WHAT CONCLUSION CAN BE DRAWN FROM THE RFP RESPONSES?

A. It appears that the merchant plant generators that responded to APS' RFP generally were not willing to accept the price volatility risk related to natural gas costs, and elected instead to pass that risk on to APS and its customers. This would indicate that market participants are well aware of the price volatility in the natural gas market and are unwilling to bear the associated risk.

Q. IS THE USE OF AN ADJUSTMENT MECHANISM TO RECOVER FUEL AND PURCHASED POWER COMMON IN THE UTILITY INDUSTRY?

A. Yes. Adjustment mechanisms are commonly used to recover both fuel and purchased power costs. These types of adjustments are utilized by both electric and natural gas utilities. A May 7, 2003 report from RRA, entitled "Fuel and Wholesale Power Cost Recovery," provided a state-by-state review of cost pass-through programs. Of the forty-nine "states" reviewed (Nebraska and Alaska, which have no regulated IOU electric utilities, were excluded, while Washington D.C. was included), 73% provide commodity cost recovery. Of the states not expressly providing a cost recovery mechanism, at least some provide effective alternatives while others have granted higher ROEs that could support the additional risk. And, none have anywhere near the customer growth that the Company faces.

Q. HAS THE COMPANY UTILIZED AN ADJUSTMENT MECHANISM IN THE PAST?

A. Yes. APS previously had an adjustment mechanism for fuel and purchased power costs. For a historical perspective on APS' past adjustment mechanism(s), see Ms.

Keene's Direct Testimony in the PSA Proceeding (pg. 3, lines 1-28 and pg. 4, lines 1-17), attached as Schedule DGR-3RB.

Q. PLEASE PROVIDE A BRIEF HISTORY OF APS' REQUEST FOR A PSA.

A. The issue of a PSA mechanism was addressed initially as part of the 1999 Settlement Agreement in Docket Nos. E-01345A-98-0473, et al. There, the Commission approved APS' use of an adjustor. Specifically, in approving a purchased power adjustor ("PPA"), the Commission noted: "We concur that a PPA would result in less risk to the Company resulting in lower costs for the Standard Offer customers." (Decision No. 61973 (October 6, 1999), at page 12, lines 24-25.) Subsequently, in Decision No. 65154 (September 10, 2002), the Commission halted the transfer of assets, thereby triggering the need for a modification of the adjustment mechanism to better reflect the situation into which APS was now placed, *i.e.,* owning generation *and* buying power from the market.

Q. WHAT IS THE MOST SIGNIFICANT MODIFICATION REQUIRED?

A. The most significant change is the inclusion of fuel costs. As a result of Decision No. 65154, the Company will continue to own generation and therefore must be able to recover its fuel costs. At the time of the 1999 APS Settlement, it was not foreseen that the Commission would change the requirement for the Company to divest its generation. Moreover, in 1999, gas tolling arrangements were not such a common purchased power attribute. Under a tolling arrangement, the purchased power buyer provides the gas fuel used by the seller. Although in actuality a component of purchased power expense, this gas fuel is classified for accounting purposes as a fuel expense.

As I previously discussed, the significant volatility of gas prices and the Company's increasing reliance on gas generation make recovery of these costs essential. Additionally, having gas costs covered allows the Company to pursue tolling agreements with merchant generators when they appear beneficial to customers without incurring a "penalty" in the form of increased fuel price risk.

Q. DID STAFF RECENTLY SUPPORT A PSA FOR APS?

A. Yes. Subsequent to the Track A decision, APS filed for, and Staff supported, a PSA to recover *both* purchased power and fuel costs. As Ms. Keene stated in her Direct Testimony in the PSA Proceeding:

> Q. In light of Decision No. 65154, is it reasonable to include fuel in the PSA at this time?
>
> A. Yes, it is reasonable because that order prevented divestiture. Additionally, natural gas has become a more important part of APS' portfolio, natural gas prices are volatile (see Appendix 2), and excluding fuel from the PSA may bias APS' decisions toward purchasing power instead of operating its generating units even when it would be more economical to generate power.

(*See* Direct Testimony of Barbara Keene, at page 4, line 25 through page 5, line 3, Docket No. E-01345A-02-0403.) Ultimately, however, the Commission approved a mechanism for recovery of purchased power costs, which was what the Commission apparently believed had been contemplated at the time of the 1999 APS Settlement, but deferred until this case consideration of a mechanism to deal with recovery of fuel costs.

Q. PLEASE DESCRIBE APS' PROPOSED PSA MECHANISM.

A. APS believes that the most effective, most accurate and fairest adjustment mechanism is a PSA that includes both fuel and purchased power. Staff agreed with this in Docket No. E-01345A-02-0403 and Staff witness Douglas Smith seems to agree in this case. Thus, APS is now proposing a PSA with the following elements:

- The use of an annual calculation, thus encompassing all seasons of the year;
- A risk/benefit sharing mechanism whereby both APS and its customers share in costs/savings from the base amount on a 90% customer /10% APS basis with a $20 million cap on APS' portion;
- Balances to be collected/refunded over 12 months unless capped;
- A cap on annual changes to the surcharge of $0.004/kWh "PCCF Bandwidth";
- Any balance not recovered due to the PCCF Bandwidth rolls forward and is recovered in the next subsequent period, subject to the PCCF Bandwidth;
- Includes off-system margin (actual vs. amount set in base rate); and
- Commission ability to review prudence of Company actions.

Mr. Rumolo includes in his testimony the proposed Plan for Administration for this PSA.

Q. WHY HAS THE COMPANY PROPOSED A 90/10 SHARING WITH A $20 MILLION CAP?

A. The Company believes that it is entitled to recover all of its prudent costs of providing service to its customers, including fuel and purchased power costs. Because some parties have raised the issue of incentives, however, the Company, in the spirit of compromise, has proposed the 90/10 sharing. The cap was proposed to protect the Company's financial integrity and to limit the level of prudent costs it would not recover. It also limits how much APS can benefit if it can reduce fuel and purchased power costs.

Q. DOES THE PSA PROPOSED BY THE COMPANY UNFAIRLY SHIFT RISK TO THE COMPANY'S CUSTOMERS?

A. Absolutely not. As a regulated utility that is required to provide power to all customers within its certificated service territory, the Company is entitled to recover all of its prudent costs. If fuel or purchased power costs rise dramatically, the Company has to be able to recover those costs. In fact, as I just described, the Company is providing additional benefit to customers through the sharing mechanism.

Q. DON'T UNREGULATED COMPANIES FACE VOLATILE COSTS THEY DON'T CURRENTLY REFLECT IN PRICES TO THEIR CUSTOMERS?

A. They might. However, they get to make the choice of whether or not to unilaterally raise prices or to stop providing their product or service until the market improves. They also are able to earn unlimited profits during times of low costs and high margins.

Q. ARE THERE OTHER FEATURES THAT APS WOULD ADD TO THE PSA IN ORDER TO PROTECT ITS CUSTOMERS FROM PRICE VOLATILITY?

A. Yes. Although first recommending that APS be denied any PSA, Staff witness Douglas Smith states in his testimony that, if the Commission elected to grant APS a PSA anyway, APS should be proactive in developing a forward hedge strategy for fuel and purchased power expenses, and that APS should communicate with Staff the details and value of each annual hedge. Given the volatility of natural gas and power prices in today's market and the increasing dependence of APS on natural gas and purchased power, APS would expect forward hedge costs to be included in each annual calculation of fuel and purchased power costs. Forward hedges can protect both the customer and APS from some portion of financial risk of price uncertainty without sacrificing reliability of supply.

B. Response to Staff Recommendation

Q. WHAT DOES STAFF RECOMMEND NOW?

A. Contrary to Staff's recommendation in the PSA proceeding supporting an adjustment mechanism for both fuel and purchased power, the 1999 APS Settlement and the PSA order, Mr. Smith recommends in this proceeding that the

Commission not approve any mechanism for APS. APS strongly disagrees with that recommendation. Mr. Smith goes on, however, to opine at page 12 of his testimony that if the Commission otherwise elects to approve a PSA, it should be a PSA that includes both fuel and purchased power. Specifically, he argues that from the customers' perspective, an adjustor that includes only purchased power may not pass along all "power cost reductions." From the regulated utility's perspective, such a limited mechanism may not "make them whole" when prices are rising. Mr. Smith also expresses a concern that a PSA that recovers purchased power only "would not provide incentives for APS to operate its system in a least-cost manner, and could encourage APS to make power supply choices that actually increase its net power supply costs." Finally, he expresses a concern that a PSA recovering only purchased power costs would not capture the effect of net power supply costs. Although APS disagrees with Mr. Smith's ultimate recommendation of no PSA at all, we agree with some of the concerns he raises regarding an adjustment mechanism limited only to purchased power.

Q. DOES APS' PROPOSAL DEAL WITH THESE CONCERNS?

A. Yes. APS believes that any effective and equitable adjustment mechanism must account for both purchased power and fuel costs and, as discussed above, has proposed a PSA that does so. APS customers realize the benefit from net power supply costs when both fuel and purchased power are included, and APS is kept whole on changes to its total fuel and purchased power costs. In addition, APS believes it is important to optimize the mix of fuel and purchased power used to serve native load customers. Implementing a PSA provides the appropriate incentive for APS and ensures that customers receive the lowest cost energy in the future.

Q. DOES MR. SMITH PRESENT ANY OTHER ARGUMENTS TO SUPPORT HIS RECOMMENDATION THAT THE COMMISSION DENY APS A PSA?

A. Yes. At page 17, line 4 of his testimony, Mr. Smith appears to focus on the issue of fixed power costs during periods of load growth. He indicates that Staff is concerned that if APS continues to experience load growth, a PSA may lead to over-recovery of total power costs if per unit fixed costs decline significantly. He further asserts a belief that a large portion of APS' power costs are fixed costs (*i.e.*, depreciation, return on equity, fixed O&M) associated with owning generating units.

Q. DO YOU AGREE WITH MR. SMITH'S ASSESSMENT OF THESE COSTS AND THEIR APPLICATION IN A PSA?

A. Absolutely not. A PSA should only adjust costs directly related to purchasing fuel or power to cover load. The fixed costs Mr. Smith alludes to are *not* fuel or purchased power costs, and are accounted for in the base rates associated with general rate case filings. There are no instances of which I am aware whereby a Commission adjusts the base rate charge to customers solely because of load growth. In other words, Mr. Smith's unfounded concerns are based on a misunderstanding of the costs covered in a PSA and are not supported by any credible evidence.

Q. MR. SMITH FURTHER STATES THAT IF RETAIL SALES INCREASE SIGNIFICANTLY, A SIMPLE ADJUSTOR COMBINED WITH BASE RATES COULD RESULT IN A FINANCIAL WINDFALL FOR APS. DO YOU AGREE WITH THAT ASSESSMENT?

A. No. Although APS has historically experienced load growth annually, Mr. Smith fails to recognize the cost of service increases APS experiences each year to serve new customers. For instance, as load growth continues, APS is required to invest capital in new substations, power transmission lines, and other capital intensive projects that are fixed in nature and are not captured in the current base rate application. Additionally, these capital additions require maintenance, thus increasing maintenance expense. They also increase depreciation and other expenses. Mr. Ewen provides specific numerical evidence rebutting Mr. Smith's assertions.

C. Response to RUCO

Q. WOULD YOU COMMENT ON DR. RICHARD ROSEN'S TESTIMONY RELATED TO THE PSA?

A. Dr. Rosen states at page 20, lines 8-11, of his testimony that "when considering whether or not a purchased power adjustment clause is needed, another important factor to consider is how the average net cost of purchased power changes on a multi-year average basis between rate cases, and not just how much volatility exists in quantity from year to year." I disagree with this statement. One reason for implementing a PSA is to provide APS and its customers a short-term mechanism for recovery or reduction of the variable cost of fuel and purchased power. Another reason for a well-designed PSA is to protect customers from price volatility while providing them with appropriate price signals. Dr. Rosen's proposal likely would result in APS having to file rate cases more frequently, and at a higher cost, than if a PSA were in place to recover (reduce) these variable costs as intended. Even with frequent rate cases, however, the use of such a general rate case "mechanism" merely ensures that refunds to customers or recovery by the Company will be very significantly delayed. Moreover, if Dr. Rosen's implicit assumption that fuel and purchased power costs do not fluctuate over longer periods of time is true (which it is not), there also would be little impact on customers from initiating a PSA. If Dr. Rosen is wrong, however, APS is at great risk.

Q. IN LIGHT OF THE ABOVE DISCUSSIONS REGARDING THE STAFF AND RUCO RECOMMENDATIONS, PLEASE SUMMARIZE APS' POSITION.

A. APS firmly believes that the implementation of a PSA for both purchased power and fuel is critical to the future economic stability of the Company. This is especially true in light of the Company's rapidly increasing dependence on natural gas to meet customer demand and the increasing volatility of natural gas prices. The PSA proposed here by the Company appropriately balances the interests of the Company and its customers and should be adopted by the Commission.

V. ADJUSTMENTS TO TEST YEAR

A. *Overview*

Q. PLEASE EXPLAIN THE ORGANIZATION OF YOUR TESTIMONY RELATED TO TEST YEAR ADJUSTMENTS.

A. I will begin by discussing additional and/or modified adjustments the Company is proposing. I will then discuss many of the numerous recommendations made by Staff, RUCO and AECC. My testimony will categorize the Staff, RUCO and AECC proposals into three subsections: 1) Staff adjustments the Company supports or at least does not oppose; 2) Staff adjustments the Company can partially support; and 3) Staff, RUCO and AECC adjustments the Company opposes. Schedules DGR-4RB and DGR-5RB detail the additional/modified APS adjustments, the unopposed Staff adjustments and the corrected Staff adjustments. Ms. Rockenberger in her Rebuttal Schedules will sponsor the RCND values for the rate base items. Mr. Propper is sponsoring the jurisdictional allocations of each adjustment. Mr. Wheeler in his Rebuttal Schedules will show the net impact on revenue requirements of these adjustments.

B. *APS' Additional and Modified Adjustments*

Q. IS THE COMPANY PROPOSING ADDITIONAL AND MODIFIED ADJUSTMENTS?

A. Yes. As I discussed in my direct testimony, the Company's intention in its filing was to seek a rate increase that would produce reasonable and prudent financial results for the Company while minimizing the impact on our customers. I also pointed out that the Company might find it necessary to include additional adjustments to maintain APS' financial health depending on the responses received to the Company's filing. The dramatic changes proposed by both Staff and RUCO, and the availability of more current information, require the Company to more fully discuss adjustments for: (1) the Palo Verde Nuclear Generating Station ("Palo Verde" or "PVNGS") Unit 2 steam generator replacement; (2) fuel and purchased power expenses; and (3) bark beetle infestation remediation costs.

Q. WILL THESE MODIFICATIONS CHANGE THE COMPANY'S BASE RATE REQUEST?

A. No. Although the combination of the additional/modified APS adjustments and the unopposed adjustments of Staff increases the calculation of revenue requirements, the Company is not increasing its base rate request.

1. Palo Verde 2 Steam Generator Replacement.

Q. WHY HAS APS MADE AN ADJUSTMENT FOR REPLACING THE STEAM GENERATORS AT PALO VERDE UNIT 2?

A. Like other nuclear generating stations, PVNGS has experienced tube cracking in the steam generators. The PVNGS owners, including APS, determined it was both necessary and economically desirable to replace Unit 2's steam generators to prevent the output of Unit 2 from dropping and to maintain the reliability of the Unit.

Q. WHAT MAJOR COMPONENTS WERE REPLACED AT PALO VERDE UNIT 2 DURING THE PROJECT?

A. Unit 2's two steam generators, three low-pressure turbine rotors, core protection calculators and pressurized heaters were replaced, thereby improving the future reliability and efficiency of Unit 2, as well as increasing Unit 2's pre-replacement output by approximately 90 megawatts (APS' share is approximately 26 megawatts). This 90-megawatt improvement was included in the simulation used to determine the Company's proposed fuel and purchased power expense and off-system margin in the Company's original filing. The "matching principle," as well as equity, would dictate that rejection of this proposal to include the steam generator replacement in rates also would necessitate removal of the 90-megawatt increase from the determination of fuel and purchased power expense and off-system margin. This would require an approximate $8 million increase in test period fuel and purchased power expense.

Q. WHEN WAS THE PALO VERDE UNIT 2 STEAM GENERATOR REPLACEMENT PROJECT COMPLETED AND WHAT WAS THE BASIS FOR DETERMINING THE STEAM GENERATOR RATE BASE ADJUSTMENT?

A. The Palo Verde Unit 2 steam generator outage was completed in December of 2003, a good year prior to when rates are likely to be effective in this case.

The adjustment was calculated using the steam generator's original cost, or book value as of December 31, 2003. The adjustment for the project includes the accumulated book depreciation and accumulated deferred income taxes as of that date. I also included a rate base pro forma to remove the $11.0 million of gross plant and accumulated depreciation as of December 31, 2003 related to the Palo Verde Unit 2 steam generator that was retired and replaced.

Q. IS THERE A CORRESPONDING OPERATING INCOME ADJUSTMENT FOR THE PALO VERDE UNIT 2 STEAM GENERATOR REPLACEMENT PROJECT?

A. Yes. Depreciation and amortization expense was adjusted to reflect one full year of depreciation on the new steam generators less the full year of depreciation on the old steam generators that occurred in the test year. Interest synchronization also has been included in the adjustment. Because fuel and purchased power expense already reflected this steam generator replacement, there are no other test period results affected by this adjustment. The rate base and operating income adjustments are shown on Schedules DGR-4RB and DGR-5RB, respectively.

2. Fuel and Purchased Power Expense.

Q. IS THE COMPANY PROPOSING AN UPDATE TO FUEL AND PURCHASED POWER EXPENSES?

A. Yes. As discussed more fully by Mr. Ewen, the Company is updating its Fuel and Purchased Power operating income pro forma adjustment. I have included this adjustment in Schedule DGR-5RB.

Q. WHY IS THE COMPANY PROPOSING SUCH AN UPDATE?

A. As I explained in my Direct Testimony, the Company sought to balance its need for a rate increase with our desire to minimize the impact on customers. In seeking to achieve that balance, the Company sought to give customers the benefit of an expectation that natural gas prices would trend 10% lower than they were at the time the rate case application was filed. Unfortunately, the expected reduction did not occur, as explained by Mr. Ewen. Moreover, because of the onerous recommendations put forth by Staff and RUCO, it is essential that the Company use the most accurate estimate possible for its going-forward fuel and purchased power expense.

3. Bark Beetle Infestation Remediation.

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR BARK BEETLES?

A. Arizona has, to date, experienced an 8-year drought that has weakened the Ponderosa pine forest trees to the extent that they became susceptible to infestation by bark beetles. Based on statistical projections performed by ecosystem scientists from the University of California at Berkley, and an independent utility vegetation management consulting group, approximately 750,000 dead or dying trees caused by this infestation are within falling distance of our power lines. Because the trend is that 31% of these trees will fall within 4 years after death, they will need to be removed over the next 3 to 5 years to both protect the transmission and distribution system and avoid the possibility of causing devastating forest fires. Based on historical data for tree removal, the average cost is $45 per tree or approximately $33,750,000 for the project.

Q. WHY IS THE COMPANY NOW CHOOSING TO INCLUDE THESE COSTS WHEN THEY WERE NOT INCLUDED AS AN ADJUSTMENT IN THE ORIGINAL FILING?

A. At the time the original case was filed, a determination of the tree removal cost was still being developed. It also was not clear as to the magnitude, if any, of federal or other assistance that might be assumed in dealing with this problem. The Company now has a solid picture of both the scope and cost of this effort. And although APS appreciates the efforts of Commissioner Mayes, Governor Napolitano and others to secure federal funds for this purpose, the Company can not prudently wait on the hopes of such funding for this project and risk damage to its transmission and distribution system or major forest fires such as those experienced in the summers of 2002 and 2003. The cost of the tree removal is obviously a valid expense to maintain system reliability and, therefore, is appropriately recovered from our customers.

Q. HAS THE COMPANY TAKEN ANY STEPS TO SEEK FEDERAL FUNDING FOR THESE COSTS?

A. Yes, we have. And as noted above, so have Commissioner Mayes, Governor Napolitano, and others. Specifically, Commissioner Mayes has written the Regional Forester in Albuquerque, New Mexico, expressing her position that the costs associated with keeping the federal forests healthy should be borne by the federal government, not the state of Arizona or utility customers. The Governor has declared a state of emergency in our forests, and twice has requested federal funds to address the emergency. Both requests were denied. The Forest Health Oversight Committee, established by the Governor, to address the overall health of the forests, developed a recommendation that would make federal funds available now, before a catastrophic fire occurs. In addition to actively participating on the Forest Health Oversight Committee, the Company has met several times with State and federal organizations to discuss availability of funding.

Q. WHAT RATEMAKING TREATMENT IS THE COMPANY PROPOSING RELATED TO THESE REMEDIATION EXPENSES?

A. The Company is proposing that these expenses be recovered through the System Benefits Adjustment Clause ("SBAC"). The SBAC Plan for Administration proposed by Mr. Rumolo describes the Company's proposal in more detail.

Q. WHAT IF THE COMPANY DOES RECEIVE GOVERNMENT FUNDING?

A. If the Company eventually receives government funding to mitigate this expense, APS would include in the SBAC a credit back to customers of all amounts received. This is the primary reason the Company has chosen to use the SBAC for this item. Mr. Rumolo has included this crediting provision in his proposed SBAC Plan of Administration.

C. Recommendations APS Supports or Does Not Oppose

Q. IS THE COMPANY OPPOSING ALL OF THE ADJUSTMENTS PROPOSED BY STAFF?

A. No. Staff made several adjustments that APS does not oppose.

Q. PLEASE IDENTIFY THE RECOMMENDED ADJUSTMENTS THAT APS IS NOT OPPOSING.

A. The Company does not oppose the following adjustments:

- Staff witness Steven Carver's recommendation to update wages and salaries as discussed on pages 50 through 53 of his testimony.
- Mr. Dittmer's recommendation regarding amortization of the Palo Verde Sale/Leaseback discussed on pages 50 through 52 of his testimony.

- The elimination of civic and charitable contributions discussed by Mr. Dittmer on pages 52 and 53 of his testimony.
- Reversal of the expense associated with the mainframe lease as discussed by Mr. Dittmer on page 33 of his testimony.

These adjustments to operating income are shown on Schedule DGR-5RB.

D. Recommendations APS Can Support in Part

Q. ARE THERE ADDITIONAL RECOMMENDATIONS APS DOES NOT OPPOSE IN PRINCIPLE OR CAN SUPPORT IN PART?

A. Yes. Staff made several recommendations that APS does not oppose in principle. APS believes, however, that the calculation of certain adjustments needs to be changed and, in some instances, objects to portions of the adjustment. The following rate base and operating adjustments fall into this category and the corrected amounts are included in Schedules DGR-4RB and DGR-5RB:

- As discussed further by Ms. Rockenberger, certain of Mr. Carver's recommendations related to cash working capital (*see* pages 6 through 42 of Mr. Carver's testimony).
- Mr. Dittmer's recommendation regarding capitalized vehicle leases and the associated leased vehicle depreciation (*see* pages 17 through 19 of Mr. Dittmer's testimony). As discussed by Mr. Froggatt, however, the Company is incorporating this change in its Cost of Capital calculation.
- Staff's proposal to include losses on reacquired debt in the cost of capital calculation consistent with Mr. Reiker's recommendation with the corresponding rate base and operating income adjustments discussed by Mr. Dittmer on pages 19, 20, 50 and 51 of his testimony. As discussed by Mr. Froggatt, however, the Company is correcting certain errors in Mr. Reiker's calculation.
- The removal of a prior period property tax expense discussed on pages 27 and 28 of Mr. Dittmer's testimony. As discussed by Mr. Froggatt, however, APS opposes other adjustments to property tax expense.
- Ms. Keene's recommendation to remove DSM costs from operating expense and to include such costs in an adjustment mechanism (*see* pages 1 through 14 of her testimony). The Company is proposing a different annual

ceiling of $10 million for DSM programs. Mr. Rumolo has used $3 million in his determination of the current charge. As discussed by Mr. Fox, however, APS also proposes to include bill assistance costs in this adjustment as well as in the adjustment mechanism. I have included in operating expense the $50,000 funding for E-3 marketing which is also discussed by Mr. Fox. Additionally, it should be noted that Ms. Jaress's proposed overall rate decrease shown on page 6 of her testimony, although including the removal of DSM costs from operating expense, did not include the $4 million DSM adjustment mechanism proposed by Ms. Keene.

- The proposed amortization of the union contract signing bonus discussed by Mr. Carver on pages 53 through 56 of his testimony. APS has corrected Mr. Carver's calculation, however. He removed one-third of the costs but to be consistent with his testimony, he should have removed two-thirds.

- As discussed in greater detail by Mr. Froggatt, certain items related to the determination of income taxes recommended by Mr. Dittmer on page 43 through 45 of his testimony.

- Mr. Dittmer's recommendation on gains on sales discussed on page 53 of his testimony. Consistent with Decision No. 64306 (December 28, 2001), however, the Company is including the required 6% annual interest on the gain from the Glen Canyon transmission line. It should be noted that although the Company is not opposing Mr. Dittmer's inclusion of the gains associated with the streetlight sales to the City of Florence and the City of Eloy in his amortization adjustment, this methodology might be considered to be inconsistent with the Commission's requirements in Decision No. 61708 (May 13, 1999) that such gains ". . . be either refunded to customers or utilized by APS for funding of programs that will directly benefit customers, such as public education programs . . .."

- As discussed further by Mr. Rumolo, certain recommendations by Ms. Keene related to Schedule 1 charges (*see* pages 19 through 23 of Ms. Keene's testimony).

E. Adjustments Opposed by APS

Q. DID STAFF AND INTERVENORS PROPOSE ADJUSTMENTS WITH WHICH THE COMPANY DISAGREES?

A. Yes. Staff, RUCO and AECC proposed several other adjustments. Except for those referenced above as not being disputed, APS opposes each of those adjustments. As I mentioned above, several of the adjustments are addressed by other APS witnesses. I will be discussing the remaining adjustments in this section of my testimony.

1. PWEC Units.

Q. DID STAFF, RUCO AND AECC MAKE ANY RECOMMENDTIONS REGARDING THE PWEC ASSETS?

A. Yes. Staff, RUCO, and AECC all recommend precluding the Company from putting the PWEC assets in rate base and therefore remove them from the rate base and operating income. APS witnesses Mr. Wheeler, Ajit Bhatti and Dr. William Hieronymus discuss the Company's opposition to these adjustments on an economic, equity and policy basis. My rebuttal testimony will focus on Staff's, RUCO's and AECC's calculation of the revenue requirement impact associated with removing the PWEC assets from APS' proposal.

Q. DO YOU HAVE ANY CONCERNS WITH THE CALCULATIONS USED BY STAFF, RUCO AND AECC TO REMOVE THESE AMOUNTS?

A. Yes. None of the proposed adjustments include the necessary corresponding adjustment to transmission rate base and operating income. When preparing the initial filing, the Company included in the PWEC rate base and operating income pro forma adjustments costs associated with PWEC transmission plant. Some portions of this transmission plant and related expenses are properly functionalized to transmission. (Consistent with Federal Energy Regulatory Commission ["FERC"] requirements, transmission plant and costs specifically associated with generation interconnection are functionalized to generation.) The portions of the PWEC transmission plant and expenses that are functionalized to transmission were removed by the Company in the transmission rate base and operating income pro forma adjustments. By not recognizing the Company's prior removal of these transmission-related costs, Staff, RUCO and AECC have essentially removed these costs twice, over-stating their non-jurisdictionalized adjustments by approximately $20.9 million in rate base and $870,000 in expenses.

2. Deferred Gain on PacifiCorp Sale.

Q. HAS STAFF MADE A RECOMMENDATION REGARDING THE TREATMENT OF THE DEFERRED GAINS ON THE PACIFICORP SALE?

A. Yes. Mr. Dittmer proposes on pages 10 through 17 of his testimony that a payment to APS by PacifiCorp be used as a current period rate base offset. PacifiCorp agreed to make this payment when it cancelled a previously agreed to construction arrangement. The construction arrangement was part of the 1991 power supply arrangement between APS and PacifiCorp and entailed APS' constructing for PacifiCorp 150 megawatts of combustion turbines (CTs) interconnected to APS' transmission system.

Q. WHAT IS THE REASON GIVEN BY MR. DITTMER FOR HIS RECOMMENDATION THAT THE PAYMENT BE AN OFFSET TO RATE BASE?

A. It appears that Mr. Dittmer's primary argument is that the 1991 Settlement Agreement (entered into between Staff and APS) and the Commission's decision approving that agreement (Decision No. 57459) did not specify the regulatory treatment for these funds prior to the agreed to amortization beginning in 2010. Mr. Dittmer asserts that it was always Staff's "intention" that the funds be a rate base credit prior to 2010 and, therefore, the funds should now be treated as a rate base credit.

Q. DO YOU AGREE WITH MR. DITTMER'S RATIONALE?

A. No. I don't know whether in 1991 Mr. Dittmer intended that the funds be treated as a rate base credit prior to 2010. I do know this was not agreed to in the 1991 Settlement Agreement, nor was it addressed in the Commission's decision approving the 1991 Settlement Agreement.

Mr. Dittmer testified that the discussions between Staff and APS surrounding the 1991 Settlement Agreement addressed the regulatory treatment of the gains and the amount and method of passing on these gains to ratepayers. I can't address whether such discussions may have taken place. The 1991 Settlement resulting from those numerous meetings and discussions between Staff and APS, however, contains no agreement to the regulatory treatment proposed by Staff of any gain prior to 2010. In fact, subtracting such gain would be inconsistent with the agreed-upon amortization of such gain, which clearly is deferred until 2010. Thus, the Company believes that no special regulatory treatment not clearly agreed to at the time, such as a credit to rate base, is required.

Had Mr. Dittmer intended that the gains be treated as a rate base credit prior to 2010, it clearly would have been stated in the 1991 Settlement Agreement. Although Mr. Dittmer argues that the 1991 Commission order that approved the PacifiCorp transaction did not prohibit treating the gain on sale as a rate base adjustment, it clearly did not require APS to offset rate base prior to the amortization of the gain beginning in 2010. Mr. Dittmer is essentially asking that the 1991 decision be modified to include another requirement that he believes should have been included.

In the Company's most recent fair value rate base determination, Decision No. 61973 (October 6, 1999), the Commission's authorized rate base did not reflect this gain as a rate base offset. It was never even proposed by Staff. Customers will fully benefit from this transaction, as recognized in the 1991 settlement decision, when the gain is amortized starting in 2010.

Q. DOES MR. DITTMER OFFER ANY OTHER RATIONALE FOR OFFSETTING RATE BASE FOR THE PACIFICORP GAIN?

A. Yes. Mr. Dittmer asserts that "investors will receive a return on an investment that simply does not exist" and that "simple equity would suggest that . . . the Company should not be entitled to earn a return on such cost-free funds."

Q. HOW DO YOU RESPOND TO HIS ARGUMENTS?

A. Because the Company has not included and has not proposed to include these funds in rate base, I find Mr. Dittmer's allegation that the Company is proposing to earn a return on these funds to be a bit misleading. Mr. Dittmer proposes to reduce rate base by the amount of the funds, thereby reducing the return earned on rate base. Although the funds may, in a sense, be "cost-free," they are funds received from PacifiCorp, not APS ratepayers. Under Mr. Dittmer's recommendation, ratepayers would benefit from funds they neither provided nor for which they were at risk. Equity would suggest that the terms spelled out in the 1991 Settlement Agreement should be adhered to.

Q. DO YOU HAVE ANY OTHER CONCERNS RELATED TO THIS ADJUSTMENT?

A. Yes. There were errors in how the adjustment was made by Mr. Dittmer. Instead of reducing rate base, Mr. Dittmer's Schedule B, Page 2 of 2, shows an increase in rate base. Mr. Dittmer, in response to discovery, has acknowledged this error. Additionally, Mr. Dittmer adjusts rate base by $20.7 million. The payment received from PacifiCorp related to the CTs was $20 million. The additional $748,000 is related to other gains and, as stated above, the Company is not opposing Mr. Dittmer's proposed treatment of these other types of gains on sales.

3. Employee Incentive Compensation.

Q. DO STAFF AND RUCO MAKE ANY RECOMMENDATIONS REGARDING THE COMPANY'S INCENTIVE COMPENSATION PROGRAMS?

A. Yes. As described by Mr. Rigsby on pages 11 through 13 of his testimony, RUCO recommends exclusion of employee incentive pay. Mr. Rigsby concluded that because the Company did not reach the earnings targets established in the incentive plan, the incentive payment should not be recovered from ratepayers. As discussed by Mr. Carver on pages 56 through 65 of his testimony, Staff is recommending a disallowance of the stock-based incentive compensation. Staff does recommend recovery of the cash-based incentive compensation that Mr. Rigsby has disallowed, however.

Q. IF THE COMPANY DID NOT REACH THE EARNINGS TARGETS ESTABLISHED IN THE PLAN, WHY WAS AN INCENTIVE PAID?

A. Under the terms of the incentive plan, the Board of Directors has discretion regarding the making and amount of incentive payments to employees. Although Pinnacle West Capital Corporation ("Pinnacle West") did not reach the targeted earnings, it was determined that reduced payments were warranted for APS because APS employees did meet the operational performance targets established in the plan. The operational targets included such items as operations and maintenance expense, reliability, safety and customer satisfaction – items directly related to the reliable, safe, cost-efficient provision of electric service to our ratepayers. Targeted earnings were not met because of the decline in the wholesale power market affecting unregulated trading margins.

Q. WHY DOES APS BELIEVE IT IS APPROPRIATE TO INCLUDE THE INCENTIVE PAYMENT IN RATES?

A. First as discussed above, the incentive payment was calculated and paid to employees based on reliability, safety, cost-efficiency and customer satisfaction targets directly related to the provision of electric service, Second, in order to ensure customers receive the most reliable and cost-effective electricity, APS must attract, retain and motivate a skilled and highly competent work force capable of meeting and even exceeding customers expectations. Providing competitive overall employee compensation is essential to attract and retain the caliber of talent necessary to continue the delivery of quality, cost effective service our customers have come to expect. A thorough competitive analysis of compensation in the utility industry shows that the vast majority of companies, including government entities, include annual variable pay, in addition to base salary. Base salary plus annual variable pay is defined as total cash compensation. APS' total cash compensation is slightly less than the market average and it is appropriate for customers to pay these costs.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH MR. RIGSBY'S CALCULATION OF THIS ADJUSTMENT?

A. Yes. Mr. Rigsby overstated the adjustment because he did not remove the $515,000 in Administrative and General ("A&G") credits that APS receives from shared plant participants. When the incentive payment is booked, total A&G expenses are booked with an off-setting A&G credit made for amounts the Company anticipates receiving from other owners of jointly-owned plants such as PVNGS. The amount of A&G included in APS expense and, therefore, the rate request is net of the $515,000 A&G credit from shared plant participants. Therefore, Mr. Rigsby has overstated his adjustment by using the gross amount of A&G and not removing the A&G credit which previously was removed by APS.

Q. WHY DOES APS BELIEVE IT IS APPROPRIATE TO INCLUDE STOCK-BASED INCENTIVE COMPENSATION IN RATES?

A. There are several reasons. First, contrary to Mr. Carver's assertions, Pinnacle West earnings are directly related to the cost-effective provision of reliable regulated electric service. APS' earnings are the primary driver of Pinnacle West's earnings and APS earnings are driven by regulated utility service. Plant outages, cost-minimization activities and even employee safety can substantially impact APS', and therefore Pinnacle West's, earnings. Thus, any payout based on Pinnacle West earnings can be directly traced to the provision of reliable, cost effective electric service to customers.

Second, incentive compensation is "cheaper" than base salary and wages. This is because many employee benefits are tied to base salary. For example, retirement benefits are calculated on base wages *excluding incentive compensation.*

Lastly, as with cash incentive pay, discussed above, APS believes that its total compensation package is necessary to attract the skilled and competent employees needed to ensure reliable, cost-effective regulated utility service. Stock-based incentive compensation is one important way to attract and keep such employees. And so long as the total compensation package offered is not excessive, and no party has claimed that it is, the specific mix of the components of that package (base pay, cash bonus, stock bonus, benefits, etc.) should be left to management and employees to negotiate in a free market.

4. Employee Severance.

Q. WHAT HAVE STAFF AND AECC RECOMMENDED WITH RESPECT TO EMPLOYEE SEVERANCE?

A. Both Mr. Carver for Staff and Mr. Higgins for AECC recommend eliminating the recovery of costs associated with the 2002 early retirement and voluntary severance program.

Q. DO YOU AGREE WITH THOSE RECOMMENDED ADJUSTMENTS?

A. No. Mr. Carver (at pages 42 through 50 of his testimony) and Mr. Higgins (at pages 26 and 27 of his testimony) both acknowledge that ratepayers are benefiting from this program. They opine that because regulatory lag does not allow for the immediate savings to be passed on to the ratepayers, however, the Company should not be allowed to recover the cost of the program.

Q. WHY SHOULD THE COMPANY BE ALLOWED TO RECOVER THE COST OF THE 2002 SEVERANCE PROGRAM?

A. First, the Company has adjusted the test year in its Payroll Adjustment to reflect the savings associated with the severance program. Because of this adjustment, ratepayers will benefit from this program each and every year after the outcome of these proceedings.

Second, regulatory lag should not be used as a basis for setting future rates. There are many costs, such as increases in meters, materials, supplies, etc., for which ratepayers enjoy benefits, but because of regulatory lag are not typically recovered through rate proceedings.

Third, severance costs such as those proposed by the Company are a legitimate business expense for which consumers generally pay.

Finally, regulatory policy should encourage the Company to manage its work force to best meet its needs and the needs of customers. One way of doing that is ensuring the proper work force level.

Q. DO YOU HAVE ANY CONCERNS RELATED TO MR. CARVER'S AND MR. HIGGINS' CALCULATIONS?

A. Yes. First, I believe Mr. Carver has under-stated his adjustment by approximately $3 million. As I explained in my Direct Testimony (page 32, lines 6 the 7), the amounts to be recovered from power plant participant owners for their share of the severance costs need to be removed from the Test Year. The mechanics of Mr.

Carver's calculation do not remove these amounts. Second, it does not appear that Mr. Higgins performed the necessary jurisdictionalized allocation.

Q. DO YOU AGREE WITH MR. RIGSBY'S AMORTIZATION PERIOD FOR TEST YEAR SEVERANCE?

A. No. Although Mr. Rigsby acknowledges that ratepayers benefit from the severance plan in the years following the current rate proceeding, he recommends a ten-year amortization period of the program cost. That amortization period is much too long and is inconsistent with prior Commission practice of using amortization periods of 3-5 years for similar expenses.

Q. WHY IS THE COMPANY USING A 3-YEAR PERIOD TO AMORTIZE THESE COSTS?

A. The accounting rules require 100 percent of severance expenses to be recorded to operating expense in the year the severance occurs, which in this case was the Test Year. For ratemaking purposes, however, the Company is matching the expenses to the expected payback period. In this case, that period is 3 years.

5. Nuclear Decommissioning Funds.

Q. HAS STAFF MADE ANY RECOMMENDATIONS REGARDING DECOMMISSIONING AT PALO VERDE?

A. Yes. Mr. Judd has recommended adjusting downward the Unit 2 decommissioning funding and reducing the total projected cost of decommissioning all three PVNGS units by changing the underlying "greenfield" assumptions used for the decommissioning study. He also has recommended increased Commission oversight of decommissioning.

Q. DOES THE COMPANY AGREE WITH THOSE RECOMMENDATIONS?

A. No. The Company has significant concerns with implementing the recommendations put forth by Mr. Judd. I will address Mr. Judd's recommendation regarding the Unit 2 funding period and Commission's oversight. Thomas LaGuardia will address Mr. Judd's recommendation on changing the "greenfield" assumptions to the decommissioning study.

Q. WHEN DOES APS PLAN TO COMPLETE FUNDING OF THE UNIT 2 DECOMMISSIONING TRUST?

A. Consistent with Commission decisions, Unit 2 decommissioning is to be fully funded by expiration of the lease in 2015.

Q. DID THE COMMISSION APPROVE THE SALE-LEASEBACK TRANSACTION?

A. Yes. The Commission approved the APS sale-leaseback transaction that imposed the above obligation upon APS in Decision No. 55120 (July 24, 1986). In that Decision, at page 8, the Commission noted:

> "The Lease Transactions and the issuance, assumption, guarantee, or incurrence of evidences of indebtedness in connection therewith are compatible with the public interest, with sound financial practices, and with the proper performance by the Company of service as a public service corporation and will not impact its ability to perform that service."

Q. DID THE NRC ALSO APPROVE THE SALE-LEASEBACK TRANSACTION?

A. Yes, it did. It also added the transaction to the Unit 2 Palo Verde license.

Q. WAS THE FUNDING PERIOD AN INTEGRAL PART OF THE LEASE TRANSACTION(S)?

A. Yes, it was.

Q. DID RATEPAYERS BENEFIT FROM THE SALE LEASEBACK AGREEMENT, INCLUDING THE REQUIREMENT THAT APS INCUR THE OBLIGATION TO FUND DECOMMISSIONING COSTS FOR UNIT 2 OVER A PERIOD LESS THAN THE UNIT'S OPERATING LICENSE LIFE?

A. Yes. Specifically, as the Commission noted in Decision No. 55931 (April 1, 1988), at pages 65-66, the gains on the transaction were factored into APS' regulated rates as a reduction to rate base. These gains likely would have been less, or non-existent, absent full funding of the decommissioning liability during the lease term. Furthermore, the accelerated funding will reduce total customer payments by permitting higher fund balances to accumulate earnings at beneficial tax rates for a longer period of time.

Q. HAS THE ACC APPROVED THE FUNDING PERIOD PROPOSED BY APS IN ITS PAST DECISIONS?

A. Yes. The ACC approved this funding period in Decision No. 57649 (December 6, 1991). This has remained consistent in all subsequent orders on decommissioning. Similarly, the post-shut down ISFSI obligation is part of the decommissioning study for the plant and should be fully funded by 2015. I see no reason to change the current funding schedule now.

Q. DO ANY OTHER COMMISSIONS ALLOW EARLY FUNDING OF DECOMMISSIONING TRUSTS?

A. Yes, an excellent example relates to another PVNGS participant. The California Public Utility Commission has allowed accelerated funding such that Southern California Edison's decommissioning trust already is fully funded.

Q. HAS MR. JUDD DETERMINED THAT HE OVER STATED HIS ADJUSTMENT RELATED TO THE FUNDING PERIOD FOR UNIT 2?

A. Yes. Attached as Schedule DGR-6RB is a copy of Staff's supplemental response to APS Data Request 4-8 indicating that Mr. Judd over stated his adjustment by $2 million.

Q. DO YOU HAVE ANY COMMENTS ON MR. JUDD'S RECOMMENDATION TO CHANGE THE ASSUMPTIONS UNDERLYING THE DECOMMISSIONING STUDY?

A. Yes, I do. Mr. La Guardia will be addressing in detail in his testimony the applicable regulations and rationale for the decommissioning approach approved by the PVNGS Participants, as well as the various calculations set forth in Mr. Judd's testimony. It also is important, however, for the Commission to understand the costly administrative burden that Mr. Judd's recommendation would entail.

As noted in Mr. LaGuardia's testimony, the "greenfield" approach used in the decommissioning study was approved by the Commission in Decision No. 55931 and in his opinion there is no factual basis supporting a change in this approach. Additionally, the "greenfield" approach used in the decommissioning study was approved by all of the PVNGS Participants and is required by the PVNGS Participation Agreement. That agreement requires *unanimous* approval of all of the Participants for any change. Based on prior experience, amending the Participation Agreement to allow APS special treatment would be very complex, involving all of the owners and, in several cases, their regulators. Thus, changing the current provision in the Participant Agreement would at best be extremely difficult and time-consuming, and may require APS to make other concessions in the Participation Agreement that could increase APS' costs by a commensurate amount.

Q. MR. JUDD HAS MADE A NUMBER OF RECOMMENDATIONS FOR ADDITIONAL COMMISSION OVERSIGHT OF THE PVNGS DECOMMISSIONING STUDY FUNDING AND ASSUMPTIONS. DO YOU AGREE WITH THOSE RECOMMENDATIONS?

A. No, I do not. I believe the Commission already provides appropriate oversight of the decommissioning process, especially in light of the extensive oversight provided by other regulatory agencies and other PVNGS participants.

Q. WOULD YOU PLEASE SUMMARIZE THE CURRENT DEGREE OF COMMISSION OVERSIGHT?

A. In Decision No. 55931, the Commission ordered APS to establish an external "qualified" nuclear decommissioning trust fund. In that Decision, the Commission established control over certain aspects of the trust, including approval of the trustee, the various fund managers, and the categories of, and limits to, permissible classes of investments for the trust. This decision also established the requirement for the Company to update the decommissioning cost study every three years and submit it to Commission.

The Commission has approved various fund managers, including RCM in Decision No. 56384 (March 9, 1989), Mellon Capital in Decision No. 58675 (June 22, 1994), DIA in Decision No. 60098 (March 19, 1997), and NISA in Decision No. 64646 (March 25, 2002). The Commission approved the current trustee for all three investment funds, Mellon Bank, in Decision No. 57426 (June 19, 1991).

In Decision No. 60098, the Commission increased the equity funding limit from $50 million to $150 million. In Decision No. 64393 (January 31, 2002), the Commission again raised funding limits and the make-up of the fund.

The Company also is required to file annual reports on the performance of the trust funds with the Commission and the funding status of each of the Participants in Palo Verde.

Q. WHAT OTHER REGULATORY AGENCIES OVERSEE APS' DECOMMISSIONING TRUSTS?

A. In addition to the Commission's oversight, the NRC requires each licensee to submit a report every two years on the status of its decommissioning fund. The Company also files an annual funding status report with FERC. In addition, other agencies, such as the GAO, have conducted periodic reviews of the decommissioning process to ensure that decommissioning is adequately funded at nuclear power plants in the United States.

Q. WHAT IS THE ROLE OF THE OTHER PALO VERDE PARTICIPANTS IN OVERSEEING APS DECOMMISSIONING TRUSTS?

A. Amendment 13 to the Palo Verde Participation Agreement created the Termination Funding Committee ("TFC") consisting of a representative from each Participant. The TFC's role is to ensure that sufficient funds are set aside and will be available to decommission all three PVNGS units. The PVNGS decommissioning study is updated every three years to adjust cost projections, incorporate technological advances and learn from the experience of other utilities' decommissioning progress. All of the PVNGS owners scrutinize the study and funding, and independently review each other's funding status and solvency annually. In addition, the Participation Agreement includes severe penalties for underfunding, including the loss of the right to that Participant's share of the power from PVNGS. Clearly, any owner of PVNGS would act to avoid such a penalty for its lowest cost, base-load resource.

6. On-Going Direct Access Expense.

Q. DID RUCO RECOMMEND EXCLUSION OF APS' PRO FORMA ADJUSTMENT FOR ON-GOING DIRECT ACCESS EXPENSE?

A. Yes. As discussed at pages 22 through 24 of Ms. Diaz Cortez's testimony, RUCO argues that there is no need to include this pro forma adjustment because it recommends a return to monopoly regulation.

Q. IF THE COMMISSION ACCEPTED RUCO'S RECOMMENDATION OF MONOPOLY REGULATION, WOULD THE COMPANY'S PRO FORMA ADJUSTMENT STILL BE APPROPRIATE?

A. In substantial part, yes. The majority of the pro forma adjustment was related to the incremental cost of the mainframe computer required for implementation of retail competition. Of the total $1,477,000 operating expense adjustment, $1,057,000 was related to the mainframe. The Company will continue to incur this expense regardless of any Commission decision on the continuance of Direct Access. Additionally, approximately $100,000 of expenses associated with the

Arizona Independent Scheduling Administrator ("AzISA") will continue until such time as FERC allows changes to APS' Open Access Transmission Tariff ("OATT") and the termination of AzISA's OATT. In fact, AzISA's filing at FERC to terminate its OATT could well mean increased APS expense associated with the AzISA because the AzISA will need to retain attorneys to make the necessary filings at FERC. Also, orderly discontinuation of operations may require additional expenditures by the AzISA. Such expenses were not included in the AzISA budget used to determine the pro forma adjustment. Should the Commission decide to discontinue Direct Access, however, it would be appropriate to modify the pro forma adjustment to eliminate approximately $300,000 in payroll-related expenses.

7. Financing Application.

Q. DO YOU HAVE ANY RESPONSE TO RUCO'S RECOMMENDATION REGARDING THE LOAN FROM APS TO PWEC?

A. Yes. On pages 12-13 of her testimony, Ms. Diaz Cortez assumes the debt will remain in place through June 2008. APS' pro forma assumes the PWEC assets will be acquired and rate based by APS by June 2004, consistent with APS' request. Even if the assets are not rate based, however, under Decision No. 65796 (April 4, 2003), the term of the loan from APS to PWEC may not exceed four years. Thus, the loan would end in May, 2007.

8. Economic Development.

Q. HAS STAFF RECOMMENDED AN ADJUSTMENT RELATED TO ECONOMIC DEVELOPMENT EXPENSES?

A. Yes. As discussed on pages 34 through 36 of Mr. Dittmer's testimony, Staff recommends the removal of expenses incurred by APS for Community Relations and Economic Development activities.

Q. WHY DOES APS OPPOSE REMOVAL OF THESE EXPENSES?

A. The Company believes that such expenses provide clear benefits to ratepayers. The Company's activities in this area attract new customers into APS' service territory. Many of these new customers are referred to as "in-fill" because they locate inside already-established areas. This means that APS' existing infrastructure is more fully utilized and, therefore, the average cost to all customers is reduced. Customers will receive the benefit of the in-fill through lower average rates.

Additionally, the Company works with state and local officials to promote economic growth throughout Arizona. For example, in 2002 APS assisted in locating to Arizona 16 companies with a capital investment of nearly $200 million and almost 1800 new jobs. These companies established operations in Winslow, Casa Grande, Eloy, Yuma, Goodyear, Buckeye, Phoenix, Peoria and Scottsdale.

9. Avnet Software Lease.

Q. DID MR. RIGSBY MAKE AN ADJUSTMENT TO REMOVE AVNET SOFTWARE LEASE EXPENSE?

A. Yes. On page 13 of his testimony, Mr. Rigsby made this recommendation.

Q. PLEASE EXPLAIN APS' POSITION REGARDING MR. RIGSBY'S RECOMMENDATION.

A. To the extent Mr. Rigsby is making the same recommendation as Staff witness Mr. Dittmer regarding the reversal of expenses associated with the mainframe lease, APS does not oppose the recommendation. It appears, however, that Mr. Rigsby is relying on a discovery response that was later revised by the Company in response to UTI 7-217. The correct amount of the reversal, as supported by Mr. Dittmer, is $631,261, not $964,630 as recommended by Mr. Rigsby. Mr. Rigsby has overstated the adjustments by $333,369.

10. Competition Rules Compliance Charge.

Q. HAS STAFF PROPOSED ADJUSTMENTS TO THE COMPANY'S CRCC?

A. Yes. As discussed on pages 19 through 25 of Ms. Lee Smith's testimony, Staff is recommending three adjustments to the Company's proposed CRCC.

Q. PLEASE DESCRIBE THE FIRST OF THESE ADJUSTMENTS.

A. Ms. Smith has proposed excluding costs APS incurred related to the formation of Desert STAR/WestConnect.

Q. IS APS OPPOSING MS. SMITH'S RECOMMENDATION RELATED TO DESERT STAR/WESTCONNECT?

A. No. Although, the Company disagrees with Ms. Smith's assertion that the costs should not be recovered because they were required by FERC (because the Electric Competition Rules also call for APS to join a RTO), the Company will make the adjustment consistent with the requirements of Rule 1609(G), APS will therefore seek recovery of the Desert STAR/WestConnect costs under FERC-jurisdictional rates. Should FERC deny APS' request for recovery, the Company will continue to defer such costs and will propose inclusion of these costs in its next rate request before this Commission.

Q. PLEASE EXPLAIN MS. SMITH'S SECOND ADJUSTMENT.

A. Ms. Smith recommends excluding $2.5 million of internal Payroll-Related expenses associated with divestiture activities unless APS' responses to pending discovery provide adequate support for the expenditures.

Q. DOES THE COMPANY AGREE WITH THIS ADJUSTMENT?

A. No. In its data request response, the Company provided substantial explanation and justification for the work performed by employees in relation to divestiture activities. Ms. Smith suggests that $2.5 million is equivalent to between 7 to 10 full-time employees ("FTE"), and she testifies that this amount of Payroll-Related expenses strikes her as high. I believe that Ms. Smith has failed to recognize the enormity and complexity of the task. Every contract, license, permit, mortgage, deed, etc. had to be analyzed and then appropriate actions taken to transfer them to PWEC. Approvals were required from lenders, participant owners, regulatory agencies, and vendors. Extensive negotiations were conducted with the owners at PVNGS, Four Corners, Navajo Generating Station, and Cholla, as well as with the Navajo Nation and the Bureau of Indian Affairs. NRC, FERC, and IRS regulations were examined and appropriate compliance filings made. Tax issues had to be investigated and applications made to obtain clearances (*e.g.*, private letter rulings). An appropriate corporate structure for PWEC had to be determined and implemented. Proper accounting and financial structures had to be put into place. And the entire process needed to be monitored and tracked to ensure that all tasks were completed in a timely manner.

Furthermore, if Ms. Smith's calculation of the number of FTEs assumed that $2.5 million was only wages and salaries, then her calculation is incorrect. The $2.5 million of Payroll-Related expense not only includes wages and salaries but also employee benefits. Thus, it would translate into fewer FTEs than posited by Ms. Smith.

Additionally, and because Ms. Smith has further adjusted the Company's CRCC by also subtracting $1.125 million for what she believed were the associated benefits to the original $2.5 million adjustment, she has removed the $1.125 million twice. As noted above, the $2.5 million Payroll-Related amount already includes the associated employee benefits.

Q. DOES MS. SMITH MAKE A THIRD RECOMMENDATION REGARDING THE CRCC?

A. Yes. Ms. Smith's third and final recommendation related to the CRCC is to question whether costs associated with the power procurement process mandated by the Commission's Track B order (Decision No. 65743) should be included in the CRCC.

Q. SHOULD THE COMMISSION INCLUDE THESE COSTS IN THE CRCC?

A. Yes. The Track B procurement was ordered by the Commission and effectively became a substitute for Rule 1606(B) of the Competition Rules. As a cost incurred in complying with the "substitute" Competition Rules, it is appropriate to include such costs in the CRCC. It also is consistent with provision 2.6 of the 1999 Settlement, which states " . . . the Commission shall, prior to December 31, 2002, approve an adjustment clause or clauses which will provide full and timely recovery beginning July 1, 2004, of the reasonable and prudent cost of . . . compliance with the Electric Competition Rules *or Commission-ordered programs or directives related to the implementation of the Electric Competition Rules*, as they may be amended from time to time, which costs shall be recovered from all customers receiving services from APS" (emphasis added). The Track B process was clearly one of the "Commission–ordered programs or directives related to the implementation of the Electric Competition Rules."

Q. IF THE COMMISSION CONCLUDED THAT TRACK B COSTS ARE NOT "DIRECTIVES RELATED TO THE IMPLEMENTATION OF THE ELECTRIC COMPETITION RULES," SHOULD SUCH COSTS NONETHELESS BE INCLUDED IN RATES?

A. Yes. These costs are still the results of a "Commission-ordered program" and thus should by fully-recovered in rates.

11. EPS System Benefits Base Rate Component.

Q. DID RUCO RECOMMEND AN ADJUSTMENT RELATED TO THE BASE RATE COMPONENT FOR EPS?

A. Yes. I am unsure why Ms. Diaz-Cortez opposed APS' pro forma adjustment (*see* pages 26 and 27 of her testimony), however. Perhaps she did not understand the intent of APS' proposed adjustment, which was merely to include in base rates the $6 million previously authorized by the Commission for EPS expenditures. Because of the timing (or "lumpiness") of EPS expenditures and the Company's method of accounting for the base rate component for EPS, recorded Test Year cost-of-service operating income did not reflect either expenses or revenues associated with the base rate component of EPS.

The Company books the base rate component of EPS capital projects expenditures to plant in service balance sheet accounts. Because such amounts are capital related, they are not booked to an expense account. The revenue from the base rate component of EPS is initially booked to revenues. To ensure that ratepayers do not pay twice for EPS projects, however, the Company reverses the revenue entry and moves the revenues into construction work in progress as a contribution in aid of construction, a balance sheet account. The contribution in aid of construction account is an offset (decrease) to the plant in service rate base accounts. The result of the accounting entries is that operating income contains $0 allowable costs for base rate EPS revenues and $0 for the allowed base rate EPS expenses. Plant in service balances for base rate EPS plant will also reflect $0 because the contributions in aid of construction will equal the EPS plant built using the base rate component of EPS. During the Test Year, approximately $5.3 million was moved from revenues to contributions in aid of construction. The $5.3 million is the amount the Company spent on base rate EPS projects and booked to plant in service. For cost-of-service purposes, however, a pro forma adjustment is required. The pro forma adjustment adds back into revenues the $5.3 million booked to contributions in aid of construction during the Test Year and also includes in expenses the $6 million authorized by the Commission.

12. Interest on Customer Deposits.

Q. HOW IS RUCO'S RECOMMENDATION REGARDING INTEREST ON CUSTOMER DEPOSITS DIFFERENT THAN THE COMPANY'S PROPOSAL?

A. Mr. Rigsby recommends on pages 13 and 14 of his testimony using the January 2, 2004 interest rate rather than the January 2, 2002 interest rate used by APS. Both RUCO's and APS' proposals use the 2002 year-end customer deposit balance. Both proposals also use the one-year constant maturities rate published on the Federal Reserve's website on the first business day of the year, as required by APS' tariff. Because APS used the interest rate in effect during the Test Year, APS' proposal reflects a reasonable estimate of the expense actually incurred by the Company during the test period.

13. Annualize Payroll.

Q. WHAT DID RUCO RECOMMEND FOR ANNUALIZING PAYROLL?

A. As discussed on pages 9 and 10 of Mr. Rigsby's testimony, RUCO is proposing to annualize payroll over multiple operating periods.

Q. DO YOU AGREE WITH THE METHODOLOGY USED BY MR. RIGSBY IN DERIVING HIS ADJUSTMENT TO TEST YEAR PAYROLL?

A. No, although I do find it interesting that for all practical purposes his total adjustment to test year payroll is almost identical to the Company's. Mr. Rigsby uses a historical approach to develop his adjustment. Historical data does not fully reflect current known and measurable changes in employee and wage levels, however.

Q. WHAT DO YOU CONSIDER THE CORRECT METHODOLOGY TO ANNUALIZE TEST YEAR PAYROLL?

A. The more accurate method for annualizing Test Year payroll is to adjust it to current known and measurable levels for employees and wages as was done by the Company and supported by Staff through Mr. Carver. Current levels of employees and wages will normally more accurately reflect the future than simply trending the past. Additionally, the payroll methodology proposed by the Company has been adopted by the Commission in previous rate cases.

14. Income Tax.

Q. DO YOU HAVE ANY FINAL GENERAL COMMENTS THAT APPLY TO ALL OF THE ADJUSTMENTS?

A. Yes. Throughout his supporting calculations, Mr. Dittmer calculated income and deferred income taxes using a composite state/federal rate of 39.42%. The income tax rate that should have been used to calculate income and deferred taxes was 39.50%. In fact, in response to Question 2-8 from APS' Second Set of Data Requests to Staff, Mr. Dittmer acknowledged that he "used a composite Federal and State tax income rate of 39.42%" but agreed that he "should have used the same composite Federal and State income tax rate used by APS (*i.e.*, 39.50%)." A copy of Staff's Response to APS Data Request 2-8 is attached as Schedule DGR-7RB. Schedules DGR-4RB and DGR-5RB reflect the appropriate 39.5% composite tax rate.

VI. <u>NON-REVENUE REQUIREMENT RECOMMENDATIONS</u>

Q. DID STAFF MAKE NON-REVENUE REQUIREMENT RECOMMENDATIONS THAT YOU WILL BE ADDRESSING?

A. Yes. I will address two of those recommendations. The first relates to Mr. Dittmer's recommendation regarding the NAC International contract, and the second relates to Ms. Jaress's discussion on the transfer of land from APS to PWEC at book value.

1. NAC International ("NAC").

Q. DOES STAFF MAKE ANY RECOMMENDATIONS REGARDING NAC INTERNATIONAL?

A. Yes. Despite acknowledging that (i) the agreement between APS and NAC was subject to the scrutiny of all of the PVNGS owners, (ii) the dry casks required at PVNGS were unique and specifically designed for the plant, (iii) the majority of the work performed under the agreement will be done by vendors with no affiliation to APS, (iv) NAC's profit on the agreement has been *de minimis*, and (v) the agreement offers a number of potential benefits for APS customers over the long run, Mr. Dittmer proposes that APS be required to competitively bid the NAC agreement.

Q. DO YOU AGREE WITH MR. DITTMER'S RECOMMENDATION?

A. No, I do not. APS should not be required to competitively bid future purchases of dry cask storage systems for PVNGS. Furthermore, the agreement negotiated between APS, with input and unanimous approval from the other PVNGS Participants, and NAC in 1999 was done at arm's length. The agreement is a good one and is beneficial to customers.

Q. MR. DITTMER REFERS TO THE GUARANTEE PROVIDED BY PINNACLE WEST AS A POTENTIAL REGULATORY CONCERN RAISED BY THE NAC AGREEMENT. DO YOU AGREE WITH THAT STATEMENT?

A. No, I do not. There is no Commission regulation or order prohibiting Pinnacle West from guaranteeing a subsidiary's performance under a contract. There are, of course, such restrictions on certain guarantees by APS, but APS has made no such guarantees regarding NAC or any of its affiliates. Second, Mr. Dittmer fails to point out in his testimony that the Pinnacle West obligations with respect to PVNGS only applies to the first 25 systems and is due to expire at the end of 2004 when the last system of the first batch is delivered. NAC's performance for future orders at PVNGS is not guaranteed by Pinnacle West.

Q. DO YOU CONSIDER THE NAC AGREEMENT WITH PVNGS TO HAVE "THE INGREDIENTS FOR AFFILIATE ABUSE" AS MR. DITTMER ASSERTS IN HIS TESTIMONY AT PAGE 61?

A. Not at all. First of all, this Commission has extensive affiliate rules for transactions between APS and its affiliates. Second, the Commission has authorized affiliate transaction accounting provisions of the kind discussed in Mr. Wheeler's Rebuttal Testimony. Third, and perhaps most important, the NAC agreement had to be approved by <u>all</u> of the Company's co-owners at PVNGS, <u>none</u> of which is affiliated in any way with APS or NAC.

2. Sale of Land By APS to PWEC at book value.

Q. DO YOU HAVE ANY COMMENTS ON MS. JARESS'S DISCUSSION REGARDING THE LAND TRANSFER TO PWEC?

A. Yes. As discussed in much greater detail in Mr. Wheeler's testimony, the Company strongly disputes the implications that the Company did anything inappropriate in transferring the land to PWEC at book value.

Q. DO GENERALLY-ACCEPTED ACCOUNTING PRINCIPLES CALL FOR TRANSFERS OF PROPERTY BETWEEN AFFILIATES TO BE ACCOUNTED FOR AT BOOK VALUE?

A. Yes. This position is supported by Interpretation No. 39 of Accounting Principles Board (predecessor to FASB) Opinion 16, "Business Combinations," which was the guidance in effect when this transaction occurred. The Interpretation sets forth examples of transfers of net assets and exchanges of shares between companies under common control that do not involve outsiders and concludes that "the assets and liabilities so transferred would be accounted for at historical cost in a manner similar to that in pooling of interests accounting." That means transfers of property between affiliates are to be accounted for at book value. Deloitte & Touche, the Company's outside auditors, reviewed our accounting for this transaction and concurred with it.

VII. RESPONSE TO COMMISSIONER GLEASON'S OCTOBER 29, 2003 LETTER

Q. WILL YOU BE PROVIDING RESPONSES TO COMMISSIONER GLEASON'S OCTOBER 29, 2003 LETTER?

A. Yes. I am providing responses to his questions entitled "PWEC Units in Rate Base – Breakdown by Asset" and parts A and B under "PWEC Units Operating Results" as they relate to non-fuel and off-system sales items. Mr. Ewen will be responding to the fuel, purchased power and off-system revenue items in parts A and B, as well as parts C and D in his rebuttal testimony. I have, however, included Mr. Ewen's information in Schedule DGR-8RB, as well as Mr. Propper's jurisdictionalized amount. Mr. Propper will answer Commissioner Gleason's questions under the heading "Redhawk Transmission."

Q. PLEASE RESTATE COMMISSIONER GLEASON'S QUESTION UNDER THE HEADING "PWEC UNITS IN RATE BASE – BREAKDOWN BY ASSET."

A. Certainly.

PWEC Units in Rate Base – Breakdown by Asset

> "Schedule B-2, page 1 of 3, adjustment no. 2, column D of the filing shows an $889,237,000 pro forma adjustment to rate base to recognize PWEC assets. Your August 7 letter also mentions this figure. Footnote 2 states that the PWEC assets include (1) West Phoenix Combined Cycle Units. 4, (2) West Phoenix Combined Cycle No. 5, (3) Redhawk Combined Cycle No. 1, (4) Redhawk Combined Cycle No. 2, and (5) Saguaro Combustion Turbine No. 3. Please provide a breakout of the amount in column D for each line item for each of the identified PWEC assets and any other significant PWEC assets such as the Redhawk Transmission. The sum of the amounts for the individual PWEC assets on each line should reconcile to the corresponding line on Schedule B-2 of the filing."

Q. WHAT IS YOUR RESPONSE?

A. The requested breakdown of the $889,237,000 Commission jurisdictional pro forma adjustment amount to rate base to recognize the PWEC assets is provided on Schedule DGR-8RB, page 2. The total Company breakdown is shown on page 1 of Schedule DGR-8RB.

Q. PLEASE RESTATE THE TEXT OF PARTS A AND B OF COMMISSIONER GLEASON'S QUESTION UNDER THE HEADING "PWEC UNITS OPERATING RESULTS."

A. Below is the text.

> "PWEC Units Operating Results
>
> Schedule C-2, page 3 of 10, adjustment no. 9, column R of the filing shows a $12,575,000 pro forma adjustment to operating income to recognize PWEC assets. Footnote 9 states that the PWEC assets include (1) West Phoenix Combined Cycle Units. 4, (2) West Phoenix Combined Cycle No. 5, (3) Redhawk Combined Cycle No. 1, (4) Redhawk Combined Cycle No. 2, and (5) Saguaro Combustion Turbine No. 3. Please provide the following information regarding adjustment no. 9.
>
> A. Break out the amount in column R for each line items for each of the identified PWEC assets and any other significant PWEC assets such as the Redhawk Transmission. The sum of the amounts for the individual PWEC assets on each line should reconcile to the corresponding line on Schedule C-2 of the filing.
>
> B. Identify and explain the basis and assumptions used to derive the amounts in column R. For example, are they actual test year amounts recorded in the general ledger or pro forma amounts based on the projected average of the years 200X to 200Y and linear growth of Z percent per year?"

Q. PLEASE PROVIDE YOUR RESPONSE TO HIS QUESTIONS.

A. With respect to item A, the breakout of the $12,575,000 jurisdictionalized pro forma adjustment to operating income to recognize the PWEC assets is provided in Schedule DGR-8RB, page 4. The total Company breakout is shown on Schedule DGR-8RB, page 3. With respect to item B, please see the following explanation of the basis and assumptions used to derive the amounts in Column R of Schedule C-2.

<u>Operating Revenue</u>

Included in operating revenue are two amounts. The first amount reflects the additional net margin that will result from increased off-system sales if the PWEC assets are included in rates. This amount was determined using a simulation of the

APS system dispatch and is further explained in the Rebuttal Testimony of Mr. Ewen.

The second amount reflects the inclusion of the PWEC Units-related debt as part of the Company's permanent capital structure. The inclusion of this debt results in a reduced weighted cost of debt. As part of APS' acquisition of the PWEC units, the debt owed by PWEC to APS will be cancelled and the loans obtained by APS in May 2003 will be treated as utility debt for rate making purposes. The incorporation of this debt in APS' capital structure is premised on the inclusion of the PWEC Units in rates with a corresponding cancellation of the PWEC/APS note in lieu of its repayment by PWEC in 2007. The impact of including this $500 million debt is a calculated amount that lowers the Company's overall long-term weighted cost of debt from 5.81% to 5.70% and changed the percentage of debt in the capital structure from approximately 50% to 55%. This lowers the overall cost of capital from 8.67% to 8.31%. The change in the rate of return has been applied to the Test Year and pro forma adjustment rate base amounts with the resulting savings included in the PWEC Units pro forma adjustment. The total amount was allocated to each of the PWEC units and to the Redhawk Transmission in Schedule DGR-8RB, pages 3 and 4, by using each asset's percentage of rate base to total PWEC rate base (*see* Schedule DGR-8RB pages 1 and 2).

Purchased Power and Fuel Costs

This amount reflects the fuel and purchased power savings associated with dispatching the more efficient PWEC Units rather than using APS' existing units or buying economy energy. This amount was determined using a simulation of the APS system dispatch and is further explained in the Rebuttal Testimony of Mr. Ewen.

Oper Rev Less Purch Pwr & Fuel Costs

This line is calculated by subtracting the amount shown in the Purchased Power and Fuel Costs line from the amount shown in the Operating Revenue line.

Operations Excluding Fuel Expense

The 2003 budgeted operations expense for each of the PWEC units was used in determining the Operations Excluding Fuel Expense, except that the operations expense for West Phoenix CC Unit No. 5 has been normalized to reflect a full year of operation.

The 2003 plant operations budget was developed using several assumptions including:

- The payroll budget is developed using actual staffing and salary levels for the individual plants plus an assumption of 9% load for overtime and premium payments. 2002 salaries were escalated 3% to arrive at the 2003 salary level. A payroll load of 45% was applied to payroll budgets to cover employee benefits expenses such as medical insurance.
- Other costs are budgeted using "base year" information on materials & supplies, contract service, water costs, etc. In most cases this information is available from actual operating experience and contracts/agreements currently in place. In some instances, projections are made based on best available information. Once base level costs are established, these costs are escalated to a 2003 value based on a 2% annual escalation factor.

Also included is the 2002 actual amount booked by the shared services organizations to PWEC operations and a pro rata share of the shared services organizations 2002 actual amount that was booked to PWEC construction. Because all construction will have ended well prior to implementation of any new rates, and indeed, has been over for sometime now, shared services activities previously charged to construction in 2002 will be re-deployed to operations and maintenance activities.

Maintenance

Maintenance expense includes two major pieces. The first, routine maintenance, is based on the 2003 budget for each of the PWEC units, except that maintenance expense for West Phoenix CC Unit No. 5 has been normalized to reflect a full year of operation. The assumptions used in developing the 2003 maintenance budget are the same as those used in developing the 2003 operations budget above.

The second piece is for overhaul maintenance. Because the Company expects the combustion turbine overhauls for the PWEC combined cycle units to occur on a 12-year cycle, this portion was determined using a forecasted 12-year average. A forecasted 6-year average was used for other major and minor overhaul expenses. Future amounts were restated in 2003 dollars and an average was calculated.

The overhaul budget was prepared based on plant operating assumptions (hours online, number of starts, capacity factor, etc.) to develop timing for necessary overhauls. Combustion turbine overhaul costs are developed using the existing maintenance contracts. Timing for other overhaul costs is also based on plant operating assumptions and includes costs associated with steam turbine overhauls, HRSG maintenance and deep well repair.

Also included in the Maintenance line is the 2002 actual amount booked by the shared services organizations to PWEC maintenance and a pro rata share of the shared services organizations 2002 actual amount that was booked to PWEC construction.

Subtotal

This is the sum of the Operations Excluding Fuel Expense and the Maintenance.

Depreciation and Amortization

The depreciation and amortization amount reflects one full year of depreciation for each of the assets. The depreciation expense was calculated based on the depreciable plant in service at December 31, 2002 for the West Phoenix CC No. 4, Saguaro and Redhawk Units. The estimated plant in service at the planned commercial operations date, June 2003, was used to calculate the depreciation expense for West Phoenix CC No. 5.

Administration and General

Included in this line is the budgeted 2003 A&G expenses at each of the PWEC Units and A&G costs from the APS and Pinnacle West shared services organization.

The budgeted A&G expenses at each of the PWEC Units is a percentage applied to payroll and a percentage applied to contract labor. This method provides a fair representation of the A&G cost for the plants.

The APS and Pinnacle West shared services organization costs consists of two components. The first component represents the 2002 actual administrative and general labor and non-labor expense incurred by the shared services departments in direct support of PWEC and a pro rata share of the shared services organizations 2002 actual amount that was booked to PWEC construction. The second component is the 2002 actual corporate and governance allocation to PWEC. This second component does not include any of the shared services labor and non-labor costs directly assigned to PWEC that are included in the first component.

Other Taxes

This amount is property tax for the PWEC Units which was forecasted for 2005 based on anticipated December 31, 2003 plant in service balances and the current valuation factor, assessment rate and property tax rates.

Total

This line is the total of Operations Excluding Fuel Expense, Maintenance, Depreciation and Amortization, Administration and General, and Other Taxes.

Operating Income Before Income Tax

This line is calculated by subtracting the amount shown in the Total line from the amount shown in the Oper Rev Less Purch Pwr & Fuel Costs line.

Interest Expense

This line is used to calculate incremental income taxes associated with the PWEC rate base and operating income pro forma adjustments. Included in this line is the taxable interest expense associated with the PWEC assets and the taxable interest expense associated with the inclusion of the $500 million PWEC Units-related debt as part of the APS' permanent capital structure. Both amounts are calculated using the weighted cost of debt or change in weighted cost of debt, as appropriate, times the applicable rate base.

Taxable Income

Taxable Income is calculated by subtracting Income Expense from Operating Income Before Income Tax.

Current Income Tax Rate – 39.5%

Income taxes are calculated by multiplying Taxable Income by the current combined statutory income tax rate of 39.5%.

Operating Income

Operating Income is calculated by subtracting the amount shown on the Current Income Tax Rate – 39.5% line from the amount shown on the Operating Income Before Income Tax line.

Q. HAS ANY PARTY TAKEN ISSUE WITH THE ELEMENTS OF THE PWEC RATE BASE AND OPERATING INCOME PRO FORMAS?

A. Staff and intervenors have suggested that APS customers receive the capital cost benefits discussed under the "Operating Revenue" portion of the Operating Income pro forma adjustment, irrespective of whether the PWEC assets are included in the Company's rate base. However, no party has contested the Company's computation of any element of either the rate base or Operating Income PWEC pro forma adjustments.

VIII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. The Company's application in this rate case proceeding struck a delicate and appropriate balance between the clear needs of the Company and the interests of APS customers, and the Company continues to believe that application should be approved as filed. Staff and RUCO, on the other hand, fail to even consider the catastrophic impact on the Company's financial health of their recommendations. Ultimately, APS customers also would suffer under those recommendations. It is difficult to comprehend how Staff and RUCO can justify recommending (i) the lowest ROE in the country for a utility located in one of the highest growth rate areas, (ii) no rate basing of assets clearly needed to provide reliable electric service at reasonable prices to our customers, and (iii) no PSA when the Company's reliance on volatile purchased power and natural gas is increasing significantly. In light of those recommendations, the Company was required to revisit the balance it struck in its application and the adjustments addressed in Direct Testimony. Although the Company now believes that an even higher revenue requirement is justified, it is not seeking to increase its base rate request.

Q. DOES THIS CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

Adoptions by Other APS Witnesses of Donald G. Robinson Direct Testimony

Topic	Adopter	Testimony Pages	Testimony Attachments	Work Papers	SFR Schedules
Normalize Weather Conditions	Ewen	Page 18 line 3-1/2 through Page 19 line 16-1/2	Attachment DGR-5 Page 3 of 27	DGR_WP8 pages 1 through 40	Schedule C-2 pages 1 of 10 column E
Annualize Customer Levels	Ewen	Page 19 line 18 through Page 22 line 13	Attachment DGR-5 Page 4 of 27	DGR_WP9 pages 1 through 22	Schedule C-2 page 2 of 10 column G
Fuel, Purchased Power and Off-System Sales	Ewen	Page 24 line 14-1/2 through Page 26 line 11	• Attachment DGR-5 page 7 of 27 • Attachment DGR-5 page 8 of 27	• DGR_WP12 pages 1 through 23 • DGR_WP13 pages 1 through 4	• Schedule C-2 page 3 of 10 column M • Schedule C-2 page 3 of 10 column O
PWEC Fuel and Purchased Power Expense and Off-System Sales	Ewen	Page 27 lines 6-1/2 through 24-1/2	Attachment DGR-5 page 9 of 27: • The portion of line 2 related to off-system revenue • Line 3	DGR_WP14 pages 5 through 10	Schedule C-2 page 3 of 10 column Q: • The portion of line 1 related to off-system revenue • Line 2
Property Taxes	Froggatt	• Page 29 lines 5-1/2 through 7-1/2 • Page 44 lines 1 through 6-1/2	• Attachment DGR-5 page 9 of 27 line 12 • Attachment DGR-5 page 24	• DGR_WP14 page 20 • DGR_WP29 pages 1 through 3	• Schedule C-2 page 3 of 10 column Q line 10 • Schedule C-2 page 8 of 10 column UU
ISFSI Expenses	Rockenberger	Page 34 line 15 through page 36 line 15	• Attachment DGR-5 page 14 of 27 • Attachment DGR-5 page 21 of 27	• DGR_WP19 pages 1 through 4 • DGR_WP26 pages 1 through 7	• Schedule C-2 page 5 of 10 column AA • Schedule C-2 page 7 of 10 column OO

**ARIZONA PUBLIC SERVICE COMPANY
SUMMARY RESULTS OF OPERATIONS
PROJECTED YEARS
(Thousands of Dollars)**

	12/31/2004			12/31/2005		
	APS Asking	**Staff Proposal**	**RUCO Proposal**	**APS Asking**	**Staff Proposal**	**RUCO Proposal**
Gross Revenues	$ 2,263,598	$ 1,852,504	$ 1,920,004	$ 2,405,450	$ 1,751,127	$ 1,868,727
Revenue Deductions & Operating Expenses	1,837,180	1,541,653	1,591,254	1,954,397	1,457,490	1,550,576
Operating Income	426,418	310,851	328,750	451,053	293,637	318,151
Other Income and (Deductions)	(1,667)	4,004	4,004	(8,411)	2,933	2,933
Interest Expense	145,810	150,637	149,753	156,562	174,695	171,107
Net Income	$ 278,941	$ 164,218	$ 183,001	$ 286,080	$ 121,875	$ 149,977
Return on Average Common Equity	11.5%	7.5%	8.3%	10.4%	5.5%	6.7%
Return on Year End Common Equity	10.4%	7.4%	8.2%	10.1%	5.6%	6.7%
Times Bond Interest Earned-Before Income Taxes	3.4	2.3	2.5	3.3	1.9	2.1
Times Total Interest & Preferred Dividends Earned-After Income Taxes	2.4	1.8	1.9	2.4	1.5	1.7
Total Debt to Total Capital	53.2%	59.3%	58.9%	52.5%	61.6%	60.6%
Funds from Operations to Average Total Debt	21.1%	15.6%	16.6%	21.2%	12.2%	13.9%
Pre-tax Interest Coverage Ratio	3.3	2.3	2.4	3.2	1.8	2.1
Funds from Operations Interest Coverage Ratio	4.3	3.4	3.6	4.2	2.8	3.1

BEFORE THE ARIZONA CORPORATION COMMISSION

MARC SPITZER
Chairman
JIM IRVIN
Commissioner
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
JEFF HATCH-MILLER
Commissioner

IN THE MATTER OF THE APPLICATION OF)
ARIZONA PUBLIC SERVICE COMPANY FOR)
APPROVAL OF ADJUSTMENT MECHANISMS)
)

DOCKET NO. E-01345A-02-0403

DIRECT

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 13, 2003

Q. Has APS ever had an adjustment mechanism?

A. Yes. APS had an adjustment clause of some form until 1989, when the Commission abolished it.

Q. Please provide some history of APS' adjustment clause.

A. The following Commission Decisions provide the history of APS' adjustment clause:

1. Decision No. 26996 (December 29, 1952) authorized a uniform adjustment clause for all areas of APS after the merger of Arizona Edison Company, Central Arizona Light and Power, and Northern Arizona Light and Power into APS. That adjustment clause was only for changes in the price of natural gas burned in electric generating stations owned or supplying energy to APS. The cost of any alternate fuel would be equated to the price of natural gas.
2. Decision No. 33813 (April 3, 1962) expanded the fuel adjustment clause to include the costs of any fuel used for the generation of electric energy.
3. Decision No. 44262 (June 14, 1974) added purchased power and allowed for automatic monthly adjustments with no prior Commission review.
4. Decision No. 46513 (October 30, 1975) modified the purchased power and fuel adjustment clause to exclude fuel handling and storage expenses, the cost of transmission and distribution losses, and the cost of company use. It also required monthly reports.
5. Decision No. 52593 (November 9, 1981) excluded fuel and related costs associated with non-jurisdictional sales to Utah Power & Light Company from the Cholla Unit No. 4 plant.
6. Decision No. 53615 (June 27, 1983) excluded all sales to non-jurisdictional customers made from specific generating units or plants.
7. Decision No. 53761 (September 30, 1983) made the following changes: (1) the charge would be computed on sales of kWh rather than on generation of kWh to

account for line losses, (2) excluded economy sales profits from the calculation, and (3) included the costs related to nuclear fuel.

8. Decision No. 54247 (November 28, 1984) authorized incentive provisions, linked to the adjustment clause, for the operation of the Palo Verde 1 and Four Corners power plants.

9. Decision No. 55118 (July 24, 1986) required annual adjustment clause review hearings, ordered that demand or capacity charges attributable to long-term purchased power contracts (over 90 days) would not be recoverable through the adjustment clause, and added additional reporting requirements.

10. Decision No. 55228 (October 9, 1986) increased the fixed percentage allowance for line losses from 8.46 percent to 9.22 percent.

11. Decision No. 56450 (April 13, 1989) abolished the adjustment clause.

Q. Why did Decision No. 56450 abolish APS' adjustment clause?

A. APS' adjustment clause was abolished because fuel prices were stable. APS was relying heavily on coal and uranium, and the prices for those fuels were fairly stable and were expected to remain stable.

Q. Did Decision No. 61973 mention fuel as a cost item to be included in an adjustment mechanism?

A. No. The decision expected that APS' generating units would be transferred to an affiliate. Therefore, APS would have no fuel costs. However, Decision No. 65154 (Track A) prevented APS from transferring its generating units.

Q. In light of Decision No. 65154, is it reasonable to include fuel in the PSA at this time?

A. Yes, it is reasonable because that order prevented divestiture. Additionally, natural gas has become a more important part of APS' portfolio, natural gas prices are volatile (see

Appendix 2), and excluding fuel from the PSA may bias APS' decisions toward purchasing power instead of operating its generating units even when it would be more economical to generate power.

POWER SUPPLY ADJUSTMENT

Q. **Please describe the proposed Power Supply Adjustment.**

A. The proposed Power Supply Adjustment (PSA) would track changes in the cost of obtaining power supplies to serve Standard Offer customers. Power supplies would include both fuel for APS' generating units and power purchased from others. The PSA would consist of a Power Cost Component Factor, a Balancing Account, a Bandwidth Limit, and an Amortization Charge.

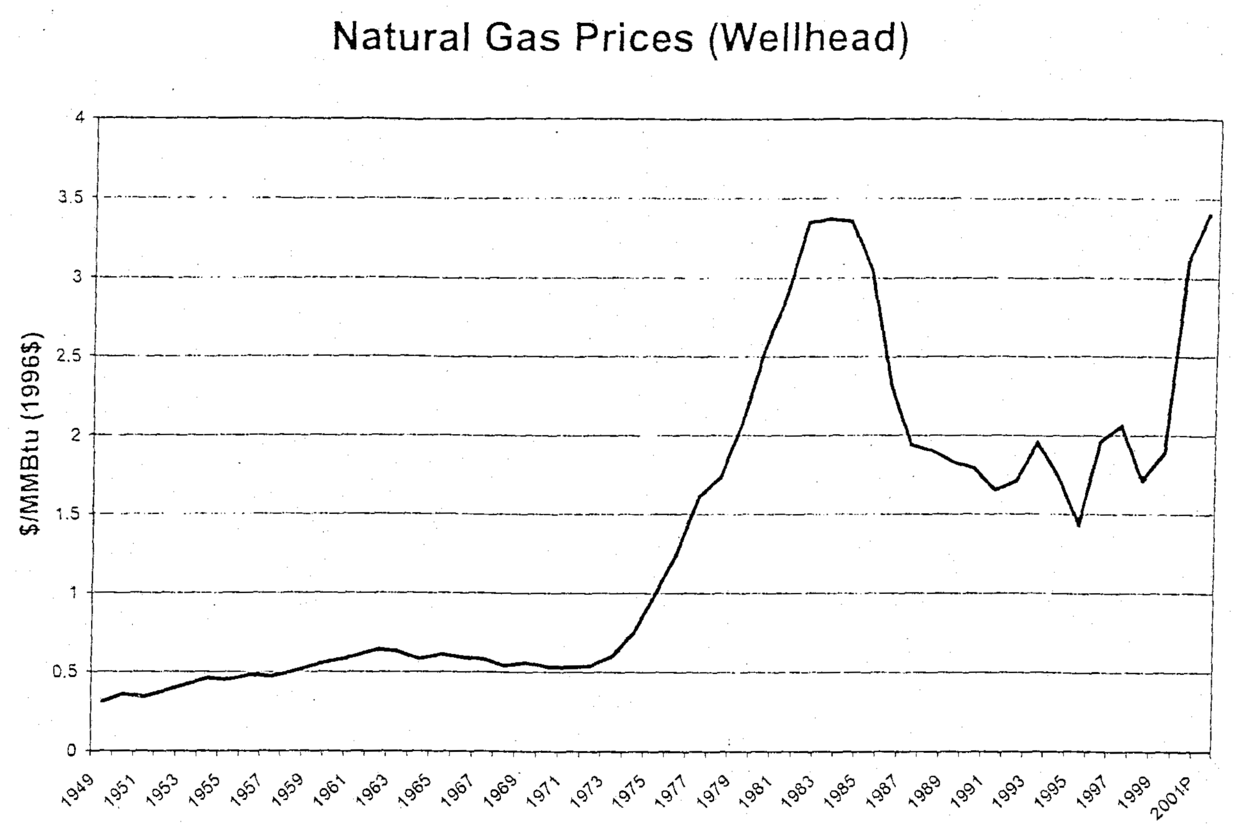
Q. **Please describe how the Power Cost Component Factor would be calculated.**

A. The Power Cost Component Factor (PCCF) would be calculated by comparing the rolling 12-month average of actual retail power supply costs to the average retail power supply cost from the test year used to determine Standard Offer rates in the upcoming rate case proceeding. The cost components would be the costs recorded in FERC Accounts 501 Fuel (steam), 518 Nuclear Fuel Expense, 547 Fuel (other production), and 555 Purchased Power. Power supply costs directly assignable to particular customers would not be included in the calculation. APS proposes to apply the PCCF to customer bills as a kilowatt-hour (kWh) charge and adjust it twice a year.

Q. **Please describe FERC accounts 501, 518, 547, and 555.**

A. Account 501 Fuel includes the cost of fuel used in the production of steam for the generation of electricity, including fuel handling and transportation. Account 518 Nuclear Fuel Expense includes the amortization of the net cost of nuclear fuel assemblies used in the production of energy. This account also includes costs for leasing fuel and for other fuels used for ancillary steam facilities. Account 547 Fuel includes the costs of

Appendix 2



Notes: Source for data is Energy Information Administration, *Annual Energy Review 2001*.
Prices are in chained 1996 dollars, calculated by using gross domestic product implicit price deflators.
Price for 2001 is preliminary.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MARC SPITZER – Chairman
JIM IRVIN
WILLIAM A. MUNDELL
MIKE GLEASON
JEFF HATCH-MILLER

IN THE MATTER OF THE APPLICATION OF)
ARIZONA PUBLIC SERVICE COMPANY FOR)
APPROVAL OF ADJUSTMENT MECHANISMS)
)

DOCKET NO. E-01345A-02-0403

SURREBUTTAL

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 20, 2003

particular, it is difficult to determine the proper amortization period without knowing the magnitude of the amount to be recovered and the impact on customer bills. If the amount to be recovered is very large, the Commission may want to amortize the amount over more than the five years proposed by APS so that the impact on customer bills will be smaller. In APS' upcoming rate case, the Commission will have more information about the magnitude of allowable compliance costs.

RESPONSE TO TESTIMONY OF MARYLEE DIAZ CORTEZ

Q. What did Ms. Diaz Cortez include in her testimony concerning APS' fuel costs?

A. On page 6 of her direct testimony, Ms. Diaz Cortez stated that APS' fuel costs have not varied materially, that natural gas prices have shown a small amount of variance from one year to the next, and that natural gas is such a small part of APS' fuel portfolio it has little effect on overall fuel costs.

Q. As to the issue of volatility, do you agree with her conclusion?

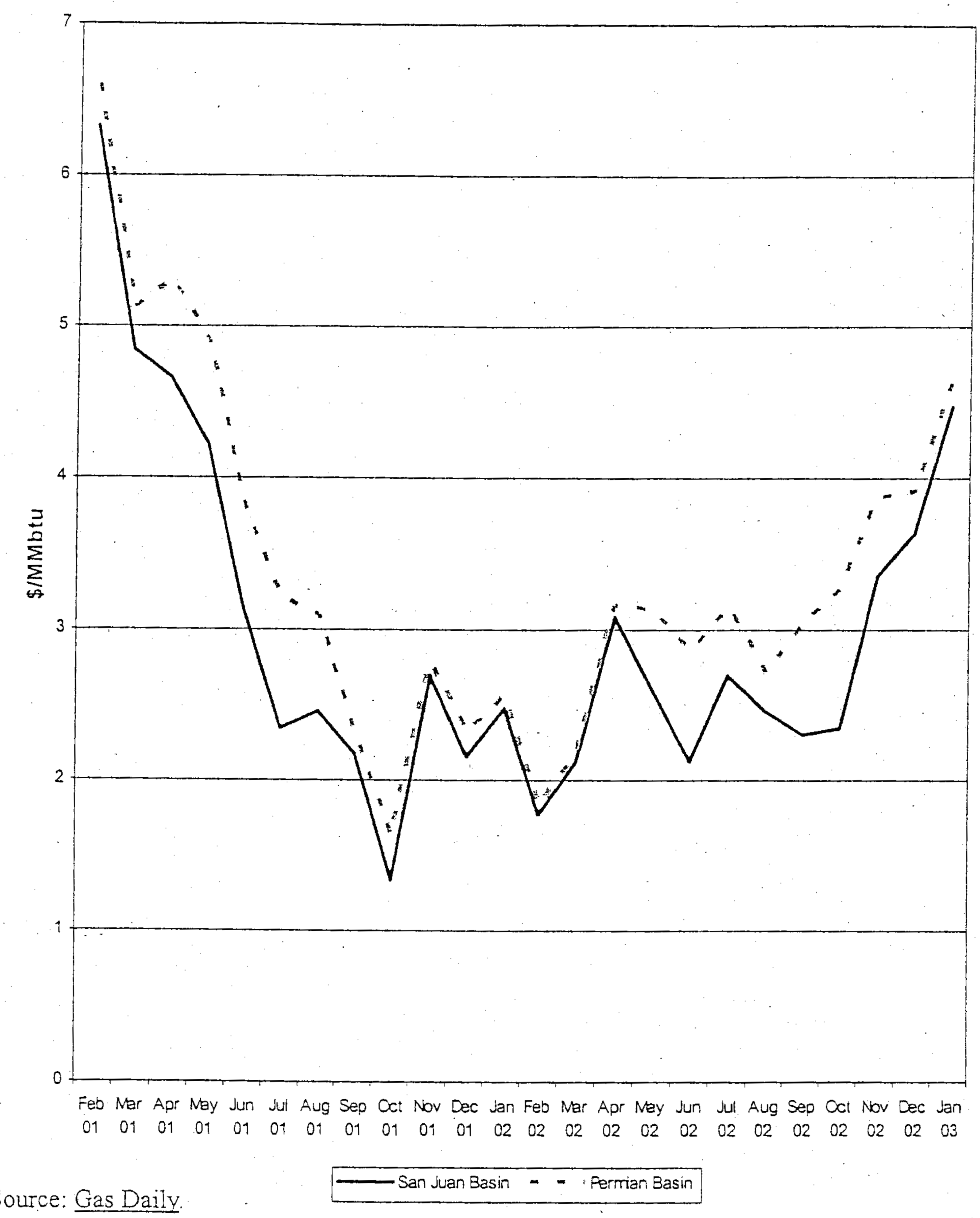
A. No. Appendix 2 of my direct testimony contains a chart that shows how natural gas prices have fluctuated over many years. The Appendix of this surrebuttal testimony contains a chart showing the volatility of more recent prices on a monthly basis. The data that I reviewed would tend to support the conclusion that natural gas prices have been arguably volatile.

Q. As to the issue of the amount of natural gas contained in APS' fuel portfolio, do you agree with her conclusion?

A. According to Ms. Diaz Cortez, natural gas fuel represents less than 10 percent of APS' fuel costs. The information that I have received from APS, however, tends to support higher percentages, i.e. 27 percent in 2000, ~~39~~ 35 percent in 2001, and ~~38~~ 24 percent in 2002. It appears that natural gas occupies a greater share of APS' fuel portfolio than it has in the past.

Appendix

Recent Natural Gas Spot Market Prices



Source: Gas Daily.

BEFORE THE ARIZONA CORPORATION COMMISSION

MARC SPITZER
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT	DOCKET NO. E-01345A-03-0437

DIRECT TESTIMONY

OF

DOUGLAS C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 3, 2004

Q. How does APS' significant reliance on natural gas-fired generation and market power purchases affect its future rate path?

A. Natural gas prices have shown considerable variance in recent years, as illustrated on Exhibit DCS-4.[1] As the Commission knows, electricity markets also tend to feature volatile prices, driven in part by natural gas prices as well as numerous other factors.

It is reasonable to expect that both gas and electricity market prices will continue to vary significantly in the foreseeable future. The Company's gas fuel costs and electricity market purchases, if not hedged, will represent a significant source of cost uncertainty in future years. Even if APS does conduct an aggressive hedging program, it will probably not be practical to eliminate all fuel cost uncertainty. Whether or not the PWEC units are included in rate base, it appears that APS' natural gas fuel requirements will represent a larger net expenditure in the near term (and, likely, a larger financial risk exposure) than the Company's projected spot market electricity transactions.

Q. Are increases in fuel prices a primary driver of APS' requested rate increase?

A. Yes. Recent spot prices for natural gas, and forward indicators for natural gas deliveries in 2004, are well above actual gas price levels that were experienced in the Test Year. The natural gas price environment also affects electricity market prices. Electricity forward prices for deliveries in 2004 have increased relative to Test Year spot market prices, as well. As I will explain below, APS' pro forma power cost analysis reflects this higher price environment.

These gas and market price increases are significant in the context of the APS power supply, even though APS gets most of its energy from nuclear and coal-fired units that feature lower and more stable fuel prices. In addition to a significant amount of owned natural gas-fired generation, APS has in place large

[1] Staff witness Barbara Keene submitted this same exhibit in Docket E-01345A-02-0403.

Exhibit DCS-4

Recent Natural Gas Spot Market Prices

Source: Gas Daily.

ARIZONA PUBLIC SERVICE COMPANY
Summary of Original Cost and RCND Rate Base Elements
Total Company and ACC Jurisdictional
Adjusted Test Year Ended 12/31/02
(Dollars in Thousands)

		Original Cost						RCND						
		Total Company			ACC			Total Company			ACC			
Line No.	Description	SFR B-1 Schedule as Filed	Adjustments to B-1	Adjusted B-1	SFR B-1 Schedule as Filed	Adjustments to B-1	Adjusted B-1	SFR B-1 Schedule as Filed	Adjustments to B-1	Adjusted B-1	SFR B-1 Schedule as Filed	Adjustments to B-1	Adjusted B-1	Line No.
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
1	Gross Utility Plant in Service	8,244,170	47,595	8,291,765	8,217,200	47,560	8,264,760	12,602,163	42,496	12,644,659	12,561,199	42,470	12,603,669	1
2	Less: Accumulated Depreciation	3,115,987	(10,847)	3,105,140	3,097,951	(10,828)	3,087,123	4,950,671	(15,946)	4,934,725	4,921,971	(15,918)	4,906,053	2
3	Net Utility Plant in Service	5,128,183	58,442	5,186,625	5,119,249	58,388	5,177,637	7,651,492	58,442	7,709,934	7,639,228	58,388	7,697,616	3
	Deductions:													
4	Deferred Taxes	1,282,822	(1,576)	1,281,246	1,281,244	(1,574)	1,279,670	1,282,822	(1,576)	1,281,246	1,281,244	(1,574)	1,279,670	4
5	Investment Tax Credits	4,040	-	4,040	4,033	-	4,033	4,040	-	4,040	4,033	-	4,033	5
6	Customer Advances for Construction	45,513	-	45,513	45,513	-	45,513	45,513	-	45,513	45,513	-	45,513	6
7	Customer Deposits	39,865	-	39,865	39,865	-	39,865	39,865	-	39,865	39,865	-	39,865	7
8	Pension Liability	49,511	-	49,511	48,751	-	48,751	49,511	-	49,511	48,751	-	48,751	8
9	Other Deferred Credits	124,050	-	124,050	123,798	-	123,798	124,050	-	124,050	123,798	-	123,798	9
10	Unamortized Gain-sale of Utility Plant	59,484	-	59,484	59,381	-	59,381	59,484	-	59,484	59,381	-	59,381	10
11	Total Deductions	1,605,285	(1,576)	1,603,709	1,602,585	(1,574)	1,601,011	1,605,285	(1,576)	1,603,709	1,602,585	(1,574)	1,601,011	11
	Additions:													
12	Regulatory Assets/Liabilities Net	300,589	(3,443)	297,146	299,822	(4,307)	295,515	300,589	(3,443)	297,146	299,822	(4,307)	295,515	12
13	Miscellaneous Deferred Debits	27,379	-	27,379	26,959	-	26,959	27,379	-	27,379	26,959	-	26,959	13
14	Depreciation Fund - Decommissioning	194,440	-	194,440	191,608	-	191,608	194,440	-	194,440	191,608	-	191,608	14
15	Allowance for Working Capital	175,713	(34,398)	141,315	172,423	(33,482)	138,941	175,713	(34,398)	141,315	172,423	(33,482)	138,941	15
16	Total Additions	698,121	(37,841)	660,280	690,812	(37,789)	653,023	698,121	(37,841)	660,280	690,812	(37,789)	653,023	16
17	Total Rate Base Before Pro Forma Adjustments	4,221,019	22,177	4,243,196	4,207,476	22,173	4,229,649	6,744,328	22,177	6,766,505	6,727,455	22,173	6,749,628	17

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Adjustments to Schedule B-2 (Pro Forma Adjustments)
(Dollars in Thousands)

		(1)		(2)		(3)	
		SFR Schedule B-2 as Filed Test Year 12/31/2002		Palo Verde 2 Replace Steam Generator		Palo Verde 2 Retire Original Steam Generator	
Line No.	Description	Total Co. (a)	ACC (b)	Total Co. (c)	ACC (d)	Total Co. (e)	ACC (f)
1.	Gross Utility Plant in Service	$ 8,244,170	$ 8,217,200	$ 77,133	$ 76,999	$ (11,042)	$ (11,023)
2.	Less: Accumulated Depreciation & Amort.	3,115,987	3,097,951	195	195	(11,042)	(11,023)
3.	Net Utility Plant in Service	5,128,183	5,119,249	76,938	76,804	-	-
4.	Deductions:						
5.	Deferred Taxes	1,282,822	1,281,244	1,447	$ 1,444	-	$ -
6.	Other Deductions	322,463	321,341				
7.	Total Deductions	1,605,285	1,602,585	1,447	1,444	-	-
8.	Total Additions	698,121	690,812				
9.	Total Rate Base	$ 4,221,019	$ 4,207,476	$ 75,491	$ 75,360	$ -	$ -

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Adjustments to Schedule B-2 (Pro Forma Adjustments)
(Dollars in Thousands)

		(4)		(5)		(6)	
		Remove Net Losses on Reacquired Debt		Remove Capitalized Vehicle Leases		Allowance for Working Capital Adjustment	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
		(g)	(h)	(i)	(j)	(k)	(l)
1.	Gross Utility Plant in Service	$ -	$ -	$ (19,553)	$ (19,253)	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.			-			
3.	Net Utility Plant in Service	-	-	(19,553)	(19,253)	-	-
4.	Deductions:						
5.	Deferred Taxes	(3,023)	(3,018)	-			
6.	Other Deductions			-			
7.	Total Deductions	(3,023)	(3,018)	-	-	-	-
8.	Total Additions	(7,652)	(7,639)			(34,398)	(33,482)
9.	Total Rate Base	$ (4,629)	$ (4,621)	$ (19,553)	$ (19,253)	$ (34,398)	$ (33,482)

ARIZONA PUBLIC SERVICE COMPANY
Original Cost Rate Base
Adjustments to Schedule B-2 (Pro Forma Adjustments)
(Dollars in Thousands)

		(7)		(8)		(9)	
		Change in Transmission Rate Base		Total Original Cost Adjustments		Adjusted Schedule B-2 Test Year 12/31/2002	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
		(m)	(n)	(o)	(p)	(q)	(r)
1.	Gross Utility Plant in Service	$ 1,057	$ 837	$ 47,595	$ 47,560	$ 8,291,765	$ 8,264,760
2.	Less: Accumulated Depreciation & Amort.			(10,847)	(10,828)	3,105,140	3,087,123
3.	Net Utility Plant in Service	1,057	837	58,442	58,388	5,186,625	5,177,637
4.	Deductions:						
5.	Deferred Taxes			(1,576)	(1,574)	1,281,246	1,279,670
6.	Other Deductions			-	-	322,463	321,341
7.	Total Deductions	-	-	(1,576)	(1,574)	1,603,709	1,601,011
8.	Total Additions	4,209	3,332	(37,841)	(37,789)	660,280	653,023
9.	Total Rate Base	$ 5,266	$ 4,169	$ 22,177	$ 22,173	$ 4,243,196	$ 4,229,649

ARIZONA PUBLIC SERVICE COMPANY
Total Company
Adjusted Test Year Income Statement
Test Year 12 Months Ended 12/31/02

(Dollars in Thousands)

Line No.	Description	Total Company: SFR Schedule C-1 As Filed (a)	Adjustments to C-1 (b)	Adjusted C-1 (c)
1	Electric Operating Revenues	1,978,176	(17,233)	1,960,943
2	Purchased power and fuel costs	568,869	6,768	575,637
3	Operating revenues less purchased power and fuel costs	1,409,307	(24,001)	1,385,306
4	Other operating expenses:			
5	Operation and maintenance	616,061	(869)	615,192
6	Depreciation and amortization	331,492	(2,927)	328,565
7	Income taxes	86,606	(7,333)	79,273
8	Other taxes	110,144	(4,077)	106,067
9	Total	1,144,303	(15,206)	1,129,097
10	Operating income	265,004	(8,795)	256,209
11	Other income (deductions):			
12	Income taxes	6,148		6,148
13	Other income	5,149		5,149
14	Other expense	(19,338)		(19,338)
15	Total	(8,041)	-	(8,041)
16	Income before income deductions	256,963	(8,795)	248,168
17	Interest deductions:			
18	Interest on long-term debt	128,462	-	128,462
19	Interest on short-term debt	5,416		5,416
20	Debt discount, premium and expense	2,888		2,888
21	AFUDC - debt	(15,150)		(15,150)
22	Total	121,616	-	121,616
23	Net Income	135,347	(8,795)	126,552

ARIZONA PUBLIC SERVICE COMPANY
ACC Jurisdiction
Adjusted Test Year Income Statement
Test Year 12 Months Ended 12/31/02

(Dollars in Thousands)

		ACC Jurisdiction		
Line No.	Description	SFR Schedule C-1 As Filed	Adjustments to C-1	Adjusted C-1
		(a)	(b)	(c)
1	Electric operating revenues	1,940,146	(16,981)	1,923,165
2	Purchased power and fuel costs	559,879	6,768	566,647
3	Operating revenues less purchased power and fuel costs	1,380,267	(23,749)	1,356,518
4	Other operating expenses:			
5	Operation and maintenance	590,073	(1,009)	589,064
6	Depreciation and amortization	329,983	(2,876)	327,107
7	Income taxes	86,144	(7,238)	78,906
8	Payroll and Other taxes	110,197	(3,969)	106,228
9	Total	1,116,397	(15,092)	1,101,305
10	Operating income	263,870	(8,657)	255,213

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Dollars in Thousands)

			(1)		(2)		(3)	
			SFR Schedule C-1 as Filed		Palo Verde 2 Steam Generator Replacement		Fuel & Purchased Power	
No.	Description		Total Co. (a)	ACC (b)	Total Co. (c)	ACC (d)	Total Co. (e)	ACC (f)
1.	Electric Operating Revenues		$ 1,978,176	$ 1,940,146	$ -	$ -	$ -	$ -
2.	Purchased Power & Fuel		568,869	559,879			6,750	6,750
3.	Oper Revenues Less Purch Pwr & Fuel Costs		1,409,307	1,380,267	0	0	(6,750)	(6,750)
	Other Operating Expenses:							
4.	Operations		616,061 /1/	590,073 /1/				
5.	Maintenance							
6.	Subtotal		616,061	590,073	0	0	0	0
7.	Depreciation and Amortization		331,492	329,983	3,066	3,061		
8.	Amortization of Gain							
9.	Administrative and General							
10.	Other Taxes		110,144	110,197				
11.	Total		1,057,697	1,030,253	3,066	3,061	0	0
12.	Operating Income		351,610	350,014	(3,066)	(3,061)	(6,750)	(6,750)
13.	Interest Expense				2,170	2,166		
14.	Taxable Income		351,610	350,014	(5,236)	(5,227)	(6,750)	(6,750)
15.	Current Income Tax Rate -	39.50%	86,606	86,144	(2,068)	(2,065)	(2,666)	(2,666)
16.	Operating Income (line 12 - line 15)		$ 265,004	$ 263,870	$ (998)	$ (996)	$ (4,084)	$ (4,084)

/1/ Operations Excluding Fuel Expense, Maintenance and Administrative and General.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Dollars in Thousands)

			(4)		(5)		(6)	
			Off-System Sales Margin		Removal of Mainframe Lease		Amortization of Union Contract Signing Bonus	
No.	Description		Total Co. (g)	ACC (h)	Total Co. (i)	ACC (j)	Total Co. (k)	ACC (l)
1.	Electric Operating Revenues		$ (17,227) /2/	$ (16,975) /2/	$ -	$ -	$ -	$ -
2.	Purchased Power & Fuel							
3.	Oper Revenues Less Purch Pwr & Fuel Costs		(17,227)	(16,975)	0	0	0	0
	Other Operating Expenses:							
4.	Operations				(631)	(621)	(549)	(540)
5.	Maintenance						(115)	(113)
6.	Subtotal		0	0	(631)	(621)	(664)	(653)
7.	Depreciation and Amortization							
8.	Amortization of Gain							
9.	Administrative and General						4	4
10.	Other Taxes							
11.	Total		0	0	(631)	(621)	(660)	(649)
12.	Operating Income		(17,227)	(16,975)	631	621	660	649
13.	Interest Expense							
14.	Taxable Income		(17,227)	(16,975)	631	621	660	649
15.	Current Income Tax Rate -	39.50%	(6,805)	(6,705)	249	245	261	256
16.	Operating Income (line 12 - line 15)		$ (10,422)	$ (10,270)	$ 382	$ 376	$ 399	$ 393

/2/ Revenue net of fuel expense.

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Dollars in Thousands)

		(7)		(8)		(9)	
		Schedule 1 Changes		System Benefits DSM		Update Payroll	
No.	Description	Total Co. (m)	ACC (n)	Total Co. (o)	ACC (p)	Total Co. (q)	ACC (r)
1.	Electric Operating Revenues	$ (6)	$ (6)	$ -	$ -	$ -	$ -
2.	Purchased Power & Fuel					18	18
3.	Oper Revenues Less Purch Pwr & Fuel Costs	(6)	(6)	0	0	(18)	(18)
	Other Operating Expenses:						
4.	Operations			(1,063)	(1,063)	988	973
5.	Maintenance					424	417
6.	Subtotal	0	0	(1,063)	(1,063)	1,412	1,390
7.	Depreciation and Amortization						
8.	Amortization of Gain						
9.	Administrative and General						
10.	Other Taxes						
11.	Total	0	0	(1,063)	(1,063)	1,412	1,390
12.	Operating Income	(6)	(6)	1,063	1,063	(1,430)	(1,408)
13.	Interest Expense						
14.	Taxable Income	(6)	(6)	1,063	1,063	(1,430)	(1,408)
15.	Current Income Tax Rate - 39.50%	(2)	(2)	420	420	(565)	(556)
16.	Operating Income (line 12 - line 15)	$ (4)	$ (4)	$ 643	$ 643	$ (865)	$ (852)

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Dollars in Thousands)

			(10)		(11)		(12)	
			Property Tax		Remove Net Losses on Reacquired Debt (adjust Reg Asset Pro Forma)		Remove Depreciation on Capitalized Vehicle Leases	
No.	Description		Total Co. (s)	ACC (t)	Total Co. (u)	ACC (v)	Total Co. (w)	ACC (x)
1.	Electric Operating Revenues		$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power & Fuel							
3.	Oper Revenues Less Purch Pwr & Fuel Costs		0	0	0	0	0	0
	Other Operating Expenses:							
4.	Operations							
5.	Maintenance							
6.	Subtotal		0	0	0	0	0	0
7.	Depreciation and Amortization				(1,530)	(1,527)	(3,315)	(3,264)
8.	Amortization of Gain							
9.	Administrative and General							
10.	Other Taxes		(4,077)	(3,969)				
11.	Total		(4,077)	(3,969)	(1,530)	(1,527)	(3,315)	(3,264)
12.	Operating Income		4,077	3,969	1,530	1,527	3,315	3,264
13.	Interest Expense				(133)	(133)	(562)	(553)
14.	Taxable Income		4,077	3,969	1,663	1,660	3,877	3,817
15.	Current Income Tax Rate -	39.50%	1,610	1,568	657	656	1,531	1,508
16.	Operating Income (line 12 - line 15)		$ 2,467	$ 2,401	$ 873	$ 871	$ 1,784	$ 1,756

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Dollars in Thousands)

No.	Description		(13) Amortization of Gains on Sales		(14) Amortization of Palo Verde Rent Levelization Regulatory Asset		(15) Removal of Civic and Charitable Contributions	
			Total Co. (y)	ACC (z)	Total Co. (aa)	ACC (bb)	Total Co. (cc)	ACC (dd)
1.	Electric Operating Revenues		$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power & Fuel							
3.	Oper Revenues Less Purch Pwr & Fuel Costs		0	0	0	0	0	0
	Other Operating Expenses:							
4.	Operations							
5.	Maintenance							
6.	Subtotal		0	0	0	0	0	0
7.	Depreciation and Amortization		(191)	(191)	(957)	(955)		
8.	Amortization of Gain							
9.	Administrative and General						(638)	(628)
10.	Other Taxes							
11.	Total		(191)	(191)	(957)	(955)	(638)	(628)
12.	Operating Income		191	191	957	955	638	628
13.	Interest Expense							
14.	Taxable Income		191	191	957	955	638	628
15.	Current Income Tax Rate -	39.50%	75	75	378	377	252	248
16.	Operating Income (line 12 - line 15)		$ 116	$ 116	$ 579	$ 578	$ 386	$ 380

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Dollars in Thousands)

			(16)		(17)		(18)	
			Adjust Income Tax Expenses		Allowance for Working Capital Adjustment		Interest Synchronization	
No.	Description		Total Co. (ee)	ACC (ff)	Total Co. (gg)	ACC (hh)	Total Co. (ii)	ACC (jj)
1.	Electric Operating Revenues		$ -	$ -	$ -	$ -	$ -	$ -
2.	Purchased Power & Fuel							
3.	Oper Revenues Less Purch Pwr & Fuel Costs		0	0	0	0	0	0
	Other Operating Expenses:							
4.	Operations							
5.	Maintenance							
6.	Subtotal		0	0	0	0	0	0
7.	Depreciation and Amortization							
8.	Amortization of Gain							
9.	Administrative and General							
10.	Other Taxes							
11.	Total		0	0	0	0	0	0
12.	Operating Income		0	0	0	0	0	0
13.	Interest Expense				(989)	(962)	(750)	(746)
14.	Taxable Income		0	0	989	962	750	746
15.	Current Income Tax Rate -	39.50%	(1,007)	(1,002)	390	380	296	295
16.	Operating Income (line 12 - line 15)		$ 1,007	$ 1,002	$ (390)	$ (380)	$ (296)	$ (295)

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Twelve Months Ended 12/31/2002
(Dollars in Thousands)

			(19)		(20)		(21)	
			Change in Transmission Operating Income Pro Forma		Total Income Statement Adjustments		Adjusted C-1	
No.	Description		Total Co. (kk)	ACC (ll)	Total Co. (mm)	ACC (nn)	Total Co. (oo)	ACC (pp)
1.	Electric Operating Revenues		$ -	$ -	$ (17,233)	$ (16,981)	$ 1,960,943	$ 1,923,165
2.	Purchased Power & Fuel				6,768	6,768	575,637	566,647
3.	Oper Revenues Less Purch Pwr & Fuel Costs		0	0	(24,001)	(23,749)	1,385,306	1,356,518
	Other Operating Expenses:							
4.	Operations		711	562	(544)	(689)	615,517	589,384
5.	Maintenance				309	304	309	304
6.	Subtotal		711	562	(235)	(385)	615,826	589,688
7.	Depreciation and Amortization				(2,927)	(2,876)	328,565	327,107
8.	Amortization of Gain				0	0	-	-
9.	Administrative and General				(634)	(624)	(634)	(624)
10.	Other Taxes				(4,077)	(3,969)	106,067	106,228
11.	Total		711	562	(7,873)	(7,854)	1,049,824	1,022,399
12.	Operating Income		(711)	(562)	(16,128)	(15,895)	335,482	334,119
13.	Interest Expense		151	120				
14.	Taxable Income		(862)	(682)	(16,128)	(15,895)	335,482	334,119
15.	Current Income Tax Rate -	39.50%	(341)	(269)	(7,333)	(7,238)	79,273	78,906
16.	Operating Income (line 12 - line 15)		$ (370)	$ (293)	$ (8,795)	$ (8,657)	$ 256,209	$ 255,213

**SUPPLEMENTAL RESPONSE
TO
SECOND SET OF DATA REQUESTS
FROM
ARIZONA PUBLIC SERVICE COMPANY TO
UTILITIES DIVISION STAFF
(Docket No. E-01345A-03-0437)
March 5, 2004**

JUDD

Q4-8. Referring to Mr. Judd's direct testimony at page 9, line 6, please explain in detail how the Unit 2 funding period adjustment reduced the annual contribution by $4.8 million. Please provide this data in electronic form with formulae intact.

Response: Accion Group, Inc. used the model provided by APS in RUCO Data Response 8, and the Schedules provided in File RC02097, to calculate the impact of adjusting the funding period to reflect funding through the license life of Unit 2 (86 Quarters) as opposed to funding through year 2015 (46 Quarters). There were two arithmetic errors in the calculation relied upon in Mr. Judd's pre-filed testimony. APS identified those errors on March 3, 2005. With the corrections, the annual contribution should be reduced by $2.8 million, and not $4.8 million as stated in the pre-filed testimony, when the Unit 2 decommissioning contribution is funded over the license life. Mr. Judd will address the miscalculation in surrebuttal testimony.

The revised model calculation for Unit 2 accompanies this response.

**SECOND SET OF DATA REQUESTS
FROM ARIZONA PUBLIC SERVICE COMPANY
TO UTILITIES DIVISION STAFF
(Docket No. E-01345A-03-0437)
February 6, 2004**

DITTMER

Q2-8 What state and federal income tax rates are being used by Mr. Dittmer for the adjustments? Please explain in detail how the income tax rates on Schedule C were derived and how they tie to the revenue conversion factor used on Schedule E.

Response: I used a composite Federal and State income tax rate of 39.42%. This is apparently a mistake. I should have used the same composite Federal and State income tax rate used by APS (i.e., 39.50%). The accounting exhibits will eventually be updated to correct for this and other mistakes and/or changes in position following APS discovery and rebuttal. Employment of a composite Federal and State income tax rate of 39.50% will also result in the revenue conversion factor of 1.6529 which was used in APS' case as well as Staff Schedule E.

ARIZONA PUBLIC SERVICE COMPANY
Rate Base
Total Company
(Thousands of Dollars)

Line No.	Description	Total	Redhawk Combined Cycle Unit No. 1	Redhawk Combined Cycle Unit No. 2	West Phoenix Combined Cycle Unit No. 5	West Phoenix Combined Cycle Unit No. 4	Saguaro Combustion Turbine No. 3	Redhawk Transmission
1.	Gross Utility Plant in Service	$ 1,021,886	$ 274,430	$ 274,030	$ 308,644	$ 78,695	$ 37,087	$ 49,000
2.	Less: Accumulated Depreciation and Amortization	$ 73,395	$ 22,228	$ 22,203	$ 14,321	$ 9,562	$ 2,793	$ 2,288
3.	Net Utility Plant in Service	$ 948,491	$ 252,202	$ 251,827	$ 294,323	$ 69,133	$ 34,294	$ 46,712
4.	Less: Total Deductions	$ 53,382	$ 6,536	$ 6,535	$ 31,253	$ 2,616	$ 4,576	$ 1,866
5.	Total Additions	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6.	Total Rate Base	$ 895,109	$ 245,666	$ 245,292	$ 263,070	$ 66,517	$ 29,718	$ 44,846

ARIZONA PUBLIC SERVICE COMPANY
Rate Base
ACC Jurisdiction
(Thousands of Dollars)

Line No.	Description	Total	Redhawk Combined Cycle Unit No. 1	Redhawk Combined Cycle Unit No. 2	West Phoenix Combined Cycle Unit No. 5	West Phoenix Combined Cycle Unit No. 4	Saguaro Combustion Turbine No. 3	Redhawk Transmission
1.	Gross Utility Plant in Service	$ 1,015,393	$ 273,954	$ 273,555	$ 308,109	$ 78,559	$ 37,023	$ 44,193
2.	Less: Accumulated Depreciation and Amortization	$ 73,045	$ 22,189	$ 22,164	$ 14,296	$ 9,545	$ 2,788	$ 2,063
3.	Net Utility Plant in Service	$ 942,348	$ 251,765	$ 251,391	$ 293,813	$ 69,014	$ 34,235	$ 42,130
4.	Less: Total Deductions	$ 53,111	$ 6,525	$ 6,524	$ 31,199	$ 2,611	$ 4,568	$ 1,684
5.	Total Additions	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6.	Total Rate Base	$ 889,237	$ 245,240	$ 244,867	$ 262,614	$ 66,403	$ 29,667	$ 40,446

ARIZONA PUBLIC SERVICE COMPANY
Operating Income
Total Company
(Thousands of Dollars)

Line No.	Description		Total	Redhawk Combined Cycle Unit No. 1	Redhawk Combined Cycle Unit No. 2	West Phoenix Combined Cycle Unit No. 5	West Phoenix Combined Cycle Unit No. 4	Saguaro Combustion Turbine No. 3	Redhawk Transmission
1.	**REVENUES:**								
2.	Operating Revenue		$ 56,779	$ 12,552	$ 12,542	$ 21,514	$ 6,649	$ 2,264	$ 1,258
3.	Fuel and Purchased Power Expenses		(34,970)	(17,732)	(17,732)	(959)	1,477	(24)	-
4.	Op Rev Less Fuel & Purchased Power Exp		$ 91,749	$ 30,284	$ 30,274	$ 22,473	$ 5,172	$ 2,288	$ 1,258
5.	**EXPENSES:**								
6.	Other Operating Expenses								
7.	Operations Excluding Fuel Expenses		14,110	4,729	4,702	3,535	913	190	41
8.	Maintenance		18,549	5,315	5,327	5,547	1,182	566	612
9.	Sub-total O&M Expenses		$ 32,659	$ 10,044	$ 10,029	$ 9,082	$ 2,095	$ 756	$ 653
10.	Depreciation and Amortization		41,541	11,494	11,494	13,210	2,821	1,375	1,147
11.	Administrative and General		8,797	2,414	2,411	2,585	654	292	441
12.	Other Taxes		11,256	2,990	2,995	2,768	1,248	707	548
13.	Total Other Operating Expenses		$ 94,253	$ 26,942	$ 26,929	$ 27,645	$ 6,818	$ 3,130	$ 2,789
14.	**OPERATING INCOME (before income tax)**		**$ (2,504)**	**$ 3,342**	**$ 3,345**	**$ (5,172)**	**$ (1,646)**	**$ (842)**	**$ (1,531)**
15.	Interest Expense		36,179	9,929	9,914	10,633	2,689	1,201	1,813
16.	Taxable Income		$ (38,683)	$ (6,587)	$ (6,569)	$ (15,805)	$ (4,335)	$ (2,043)	$ (3,344)
17.	Income Tax at	39.5%	(15,280)	(2,602)	(2,595)	(6,243)	(1,712)	(807)	(1,321)
18.	**OPERATING INCOME AFTER TAX**		**$ 12,776**	**$ 5,944**	**$ 5,940**	**$ 1,071**	**$ 66**	**$ (35)**	**$ (210)**

ARIZONA PUBLIC SERVICE COMPANY
Operating Income
ACC Jurisdiction
(Thousands of Dollars)

Line No.	Description		Total	Redhawk Combined Cycle Unit No. 1	Redhawk Combined Cycle Unit No. 2	West Phoenix Combined Cycle Unit No. 5	West Phoenix Combined Cycle Unit No. 4	Saguaro Combustion Turbine No. 3	Redhawk Transmission
1.	**REVENUES:**								
2.	Operating Revenue		$ 56,237	$ 12,481	$ 12,470	$ 21,320	$ 6,583	$ 2,244	$ 1,139
3.	Fuel and Purchased Power Expenses		(34,970)	(17,732)	(17,732)	(959)	1,477	(24)	-
4.	Op Rev Less Fuel & Purchased Power Exp		$ 91,207	$ 24,637	$ 23,308	$ 22,279	$ 5,106	$ 2,268	$ 1,139
5.	**EXPENSES:**								
6.	Other Operating Expenses								
7.	Operations Excluding Fuel Expenses		14,086	4,721	4,694	3,529	911	190	41
8.	Maintenance		18,390	5,306	5,318	5,537	1,180	565	484
9.	Sub-total O&M Expenses		$ 32,476	$ 10,027	$ 10,012	$ 9,066	$ 2,091	$ 755	$ 525
10.	Depreciation and Amortization		41,469	11,474	11,474	13,187	2,816	1,373	1,145
11.	Administrative and General		8,782	2,410	2,407	2,581	653	291	440
12.	Other Taxes		11,184	2,985	2,990	2,763	1,246	706	494
13.	*Total Other Operating Expenses*		$ 93,911	$ 26,896	$ 26,883	$ 27,597	$ 6,806	$ 3,125	$ 2,604
14.	**OPERATING INCOME (before income tax)**		**$ (2,704)**	**$ (2,259)**	**$ (3,575)**	**$ (5,318)**	**$ (1,700)**	**$ (857)**	**$ (1,465)**
15.	Interest Expense		35,977	9,922	9,907	10,625	2,687	1,200	1,636
16.	Taxable Income		$ (38,681)	$ (12,181)	$ (13,482)	$ (15,943)	$ (4,387)	$ (2,057)	$ (3,101)
17.	Income Tax at	39.5%	(15,279)	(4,811)	(5,325)	(6,297)	(1,733)	(813)	(1,225)
18.	**OPERATING INCOME AFTER TAX**		**$ 12,575**	**$ 2,552**	**$ 1,750**	**$ 979**	**$ 33**	**$ (44)**	**$ (240)**

APS-5R

EXHIBIT
tabbies
APS-5R
admitted

REBUTTAL TESTIMONY OF

CHRIS N. FROGGATT

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

Table of Contents

REBUTTAL TESTIMONY OF CHRIS N. FROGGATT
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME AND POSITION WITH APS.

A. My name is Chris N. Froggatt, and I am Vice President and Controller for Arizona Public Service Company ("APS" or "Company").

Q. ARE YOU THE SAME CHRIS N. FROGGATT WHO PROVIDED DIRECT TESTIMONY ON BEHALF OF APS IN THIS MATTER?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address cost-of-capital and tax-related issues raised by Arizona Corporation Commission ("Commission") Staff and other intervenors in their Direct Testimony. Specifically, I respond to Staff witness Jim Dittmer and RUCO witness William Rigsby regarding proposed property tax adjustments. I then address other tax-related issues raised in their testimony. I also respond to Staff witnesses Joel Reiker and Mr. Dittmer with respect to their proposal and related calculation to remove losses on reacquired debt from rate base and instead include those losses in the cost of capital calculation via an adjustment to the cost of debt. Finally, I discuss the calculation of the appropriate cost of capital given certain proposed adjustments, and the correct capital structure of APS.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Staff and RUCO both proposed adjustments to APS' property tax expense. While the Company agrees with one of Mr. Dittmer's proposed adjustments, APS disagrees with his proposed calculation of property tax expense. To use the most current information available, as Mr. Dittmer advocates, the most recent property tax rate needs to be applied to the most recent assessed property values of the taxable property proposed to be included in the Company's rate base. Because the most recent assessed property values reflect the test year, this approach is more accurate than using an assessed value from 2001, which would result from Mr. Dittmer's proposed adjustment. RUCO witness William Rigsby's proposed property tax adjustment is incorrect because he applied the wrong statutory valuation process to some of the Company's property and he understates property tax expense by effectively removing the property tax expense relating to certain transmission assets twice.

I will discuss Staff's proposed income tax adjustments that APS does not oppose. And, although APS acknowledges that Mr. Reiker's proposal for an adjustment for unamortized gains and losses on reacquired debt is reasonable, there are several errors that were made in Staff's calculation of the corresponding adjustment. I will correct the calculation of the proposed adjustment for unamortized gains and losses on reacquired debt. Finally, I will discuss the capital structure for APS, and the calculation of the Company's corrected cost of capital.

III. STAFF AND RUCO PROPERTY TAX ADJUSTMENTS

A. STAFF ADJUSTMENT

Q. HAVE YOU EVALUATED THE TWO ADJUSTMENTS RECOMMENDED BY MR. DITTMER TO REDUCE APS' PROPERTY TAX EXPENSE?

A. Yes. In Mr. Dittmer's direct testimony, he recommends two adjustments to test year property tax expense. First, he proposes removing a "prior period" payment of $3,793,668 for settlement of tribal taxes from 2001 that was paid and recorded as property tax expense in 2002. The Company does not oppose this adjustment and the effect of the adjustment is shown on Schedule CNF-1RB. Second, Mr. Dittmer proposes changes to the ongoing level of property tax to be used.

Q. DOES THE COMPANY AGREE WITH MR. DITTMER'S SECOND PROPOSED ADJUSTMENT TO CHANGE THE LEVEL OF PROPERTY TAXES?

A. No. Mr. Dittmer recommends using the Company's 2003 actual property taxes as the ongoing level of Arizona property tax expense for APS, because that amount is more current than the 2002 data that was available when APS filed its application. I agree with Mr. Dittmer that updating property tax expense to reflect more current information is appropriate, but I disagree with how Mr. Dittmer modifies the property tax expense to reflect more current information.

Q. HOW SHOULD PROPERTY TAX EXPENSE BE DETERMINED TO REFLECT THE MOST CURRENT INFORMATION AVAILABLE?

A. To reflect the most current information available as Mr. Dittmer proposes, Arizona ongoing property tax expense should be derived by using the most recent assessed property values, which have now been received from the Arizona Department of Revenue and which are based on assets owned by APS at the end of 2002. The most recent assessed property values correspond to the test year because there is a two-year lag in the state's assessment process. However, because the 2004 property tax rate is not yet known, the most recent tax rate we do know should be applied to the most recent assessed property values. This calculation can be shown as follows:

$$\text{Property Tax Expense} = \underset{\text{(From 2004 Assessment)}}{\text{2002 Property Values}} \times \text{2003 Composite Property Tax Rate}$$

$$\text{2003 Composite Property Tax Rate} = \left(\frac{\text{2003 Property Taxes Paid}}{\underset{\text{(From 2003 Assessment)}}{\text{2001 Property Values}}} \right)$$

Q. WHY DO YOU BELIEVE THAT THE 2003 PROPERTY TAX RATE IS THE MOST APPROPRIATE PROPERTY TAX RATE TO USE?

A. Mr. Dittmer correctly notes that the composite property tax rate varies from year-to-year. The rate was 9.56% in the test year, but declined to 9.34% in 2003. The 2003 composite property tax rate is the most current rate available and thus is reasonable to use in deriving an ongoing Arizona property tax expense. However, Mr. Dittmer proposes to use only the 2003 property tax <u>amount</u> as the ongoing level of property tax expense.

Q. PLEASE EXPLAIN WHY THE 2004 FULL CASH VALUES SHOULD BE USED IN DETERMINING PROPERTY TAX EXPENSE?

A. The 2004 Full Cash Values are now known because APS has received these values from the Arizona Department of Revenue. The 2004 values reflect the value of the Company's assets at the end of the 2002 Test Year. Mr. Dittmer's proposal uses asset values as of the end of 2001.

Q. DO YOU AGREE WITH THE CALCULATION OF THE 2003 PROPERTY TAX RATE OF 9.25 PERCENT CITED BY MR. DITTMER IN HIS TESTIMONY?

A. No, but only because the property values needed to calculate the property tax rate that were provided to Mr. Dittmer in November 2003 changed. APS originally reported to Mr. Dittmer a "Full Cash Value–Net Book Value" total of

$2,923,694,399 for transmission and distribution property for the 2003 tax year. This was the value originally computed by the Arizona Department of Revenue. However, APS contested this value and prevailed at the Arizona State Board of Equalization. Based on the Board of Equalization's decision, the correct "Full Cash Value–Net Book Value" for transmission and distribution property should be $2,855,635,605. When the correct value is used to determine the composite property tax rate, the 2003 rate is 9.34% rather than 9.25%.

Q. BASED ON THIS MOST RECENT INFORMATION, WHAT AMOUNT SHOULD BE USED TO REFLECT THE ONGOING LEVEL OF ARIZONA PROPERTY TAX EXPENSE?

A. Multiplying the most current 2003 composite property tax rate by the most current full cash values for property as of the end of the test year, the ongoing Arizona property tax expense should be $106.9 million rather than the $102.3 million proposed by Mr. Dittmer. The Company's calculation on this adjustment results in a $283,000 reduction to the property tax expense included in APS' Application, as shown on Schedule CNF-1RB.

Q. ARE THERE ANY OTHER ISSUES RELATING TO PROPERTY TAXES THAT MAY AFFECT THE DETERMINATION OF ONGOING ARIZONA PROPERTY TAX EXPENSE?

A. Yes. I think that the approach I recommend is still conservative. APS and the Arizona Department of Revenue currently are in litigation over a property tax issue. APS prevailed at the Board of Equalization and the Department of Revenue appealed that decision to the Tax Court. If the Department of Revenue were to ultimately prevail on the issue being litigated, APS' 2004 Full Cash Value would increase by almost $65 million. This increase in full cash value would result in an ongoing property tax expense of $108.4 million based on APS' proposed methodology. Although we believe we are correct on the merits of the issue being litigated, I think the uncertainty over the ultimate judicial outcome and its potential effect on the Company's tax expense provides even more justification for using the $106.9 million amount I am proposing rather than the $102.3 million amount proposed by Mr. Dittmer.

B. RUCO ADJUSTMENT

Q. WHAT ADJUSTMENT TO PROPERTY TAX EXPENSE DOES RUCO WITNESS RIGSBY PROPOSE?

A. Mr. Rigsby recommended reducing APS' ongoing Arizona property tax expense by $3,760,000.

Q. HOW DOES MR. RIGSBY CALCULATE HIS ADJUSTMENT?

A. Mr. Rigsby's adjustment was calculated by starting with APS' adjusted non-jurisdictionalized test year plant in service amount, and then reversing APS' pro-forma adjustment relating to PWEC assets. This revised plant in service amount was then reduced by land and transportation assets and accumulated depreciation, and increased to include materials and supplies and 50 percent of construction work in progress to arrive at APS' Full Cash Value. Mr. Rigsby then multiplied the Full Cash Value by 25 percent to calculate APS' assessed value, which he then multiplied by a property tax rate of 9.60 percent. This calculation results in an Arizona property tax expense of $103,381,000. Mr. Rigsby then subtracts this proposed property tax expense amount from APS' originally-proposed Arizona property tax expense amount of $107,141,000 to arrive at his adjustment of $3,760,000.

Q. DOES APS AGREE WITH THIS ADJUSTMENT?

A. No. APS does not agree with this adjustment. First, Mr. Rigsby's approach does not follow Arizona tax laws. Second, Mr. Rigsby's approach results in an understatement of property tax expense by twice removing the property taxes relating to transmission assets and generation plant functionalized to ancillary services.

Q. PLEASE EXPLAIN WHY MR. RIGBY'S APPROACH DOES NOT COMPORT WITH ARIZONA TAX LAW.

A. The methodology used by Mr. Rigsby would be partially correct for determining transmission and distribution property tax expense under A.R.S. § 42-14154, but it is not appropriate to use the same methodology in determining generation property tax expense under A.R.S.. § 42-14156. The latter statute specifies a different valuation methodology. He simply missed the different calculations required by the statute addressing generation property.

Q. PLEASE EXPLAIN WHY MR. RIGBY'S APPROACH REMOVES CERTAIN PROPERTY TAX EXPENSE TWICE.

A. Mr. Rigsby starts with APS' non-jurisdictionalized adjusted test year plant in service, from which he reverses APS' pro-forma adjustment for the PWEC assets. However, Mr. Rigsby does not reverse APS' pro-forma adjustment for transmission assets, which includes some generation plant that is functionalized to ancillary services. It is necessary to include these assets initially in the calculation because the property tax expense relating to these assets is removed through an APS pro-forma adjustment to the income statement. Mr. Rigsby's approach effectively removes property taxes relating to these specific assets twice, once through the rate base and again by accepting APS' pro-forma adjustment to the income statement. Using the composite property tax rate developed by Mr. Rigsby, this error alone understates APS' on-going Arizona property tax expense by approximately $18,350,000.

Q. DOES APS AGREE WITH MR. RIGSBY'S USE OF THE TEST YEAR FOR PLANT IN SERVICE AMOUNTS TO CALCULATE APS' ASSESSED VALUES?

A. Yes, although APS does not agree with the method used by Mr. Rigsby to compute ongoing property tax expense, the Company does agree that the test year is the appropriate year for determining plant-in-service amounts. As stated previously, the assets owned by APS as of December 31, 2002 are used to calculate the property tax values for the Tax Year 2004 and APS has received the final full cash values for the Tax Year 2004.

Q. DOES APS AGREE WITH MR. RIGSBY'S USE OF THE 2002 APS AVERAGE TAX RATE?

A. No. As stated previously, APS agrees with Mr. Dittmer that it is more appropriate to use the most current data. For 2003, the most current year for which a composite tax rate is available, the rate is 9.34 percent.

Q. WHAT AMOUNT DOES APS BELIEVE SHOULD BE USED TO REFLECT AN ONGOING LEVEL OF PROPERTY TAX EXPENSE FOR ARIZONA?

A. As stated earlier in my rebuttal testimony, using the most current APS "composite property tax rate" and the most current full cash values known, ongoing Arizona property tax expense should be \$106.9 million. As such, the \$103.4 million of Arizona property tax expense proposed by Mr. Rigsby understates that expense by \$3.5 million.

IV. <u>STAFF INCOME TAX ADJUSTMENTS</u>

Q. MR. DITTMER PROPOSES AN ADJUSTMENT OF \$1,540,000 TO REFLECT STATE INCOME TAX CREDITS. DOES APS OPPOSE THIS ADJUSTMENT?

A. No. Although tax credits may be repealed subsequent to the test year, and Mr. Dittmer recognizes that one tax credit has been repealed, APS does not oppose Mr. Dittmer's proposed adjustment. I would note, however, that there is a typographical error on page 44 of Mr. Dittmer's written testimony where he states that the tax credit for pollution control property was $1,167,690. The correct amount for the pollution control property tax credit is $322,486. The correct amount appears to have been the amount used in calculating the $1,540,000 adjustment shown on Schedule C-18 of the Joint Accounting Schedules.

Q. MR. DITTMER ALSO PROPOSES ACCOUNTING FOR PERMANENT DIFFERENCES IN DERIVING INCOME TAX EXPENSE. DO YOU AGREE WITH MR. DITTMER'S RECOMMENDATION?

A. Yes. On Schedule C-18, Mr. Dittmer proposes an increase of $533,000 in the 2002 income tax expense due to the non-deductibility of meal and entertainment expense. We agree with his recommendation on this issue. The effect of both of these income tax adjustments are shown on Schedule CNF-1RB.

V. EXCESS DEFERRED TAXES

Q. DID MR. DITTMER TAKE ISSUE WITH THE COMPANY'S AMORTIZATION OF EXCESS ACCUMULATED DEFERRED INCOME TAXES?

A. Mr. Dittmer stated in his testimony that he was still evaluating whether there needed to be an adjustment to address excess deferred taxes. APS has provided information to Mr. Dittmer explaining how the Company's deferred tax accounting correctly reflects the excess deferred taxes he was evaluating. It is my understanding that after reviewing the Company's analysis, Mr. Dittmer is now satisfied and will not propose an adjustment.

VI. STAFF'S UNAMORTIZED GAINS AND LOSSES ON REACQUIRED DEBT ADJUSTMENT

Q. DOES APS AGREE WITH STAFF'S ADJUSTMENTS TO RATE BASE, COST OF SERVICE AND THE COST OF DEBT RELATED TO GAINS AND LOSSES ON REACQUIRED DEBT?

A. No. Staff witnesses Reiker and Dittmer propose excluding $7.7 million (total company) of "net" loss on reacquired debt from rate base and the recovery of such costs through recognition of higher interest costs associated with debt instruments issued to refinance the debt instruments retired. While APS agrees that the concept may be reasonable, there are several errors in the adjustments.

Q. WHAT ARE THE ERRORS IN THE ADJUSTMENTS MADE BY STAFF?

First, Staff has removed the unamortized "net" loss on reacquired debt but not the associated accumulated deferred income taxes. These costs are deductions for tax purposes when the related debt is retired. The deferred taxes reverse as the associated regulatory asset is amortized. The adjustment for accumulated deferred income taxes on the $7.7 million rate base adjustment is approximately $3.0 million (total Company). This reduces Mr. Dittmer's proposed rate base adjustment to $4.7 million. Second, as noted in Staff's response to Data Request 2-2, "Staff assumed that unamortized debt discount and expense are re-amortized over the life of the new debt (thus reflected in 'Net Proceeds from Issue' in the Company's response to STF 3-10)." This assumption is incorrect. The "Net Proceeds from Issue" in the Company's response to STF 3-10 relates only to the new issue. If the unamortized losses were amortized over the remaining life of the original issues, interest expense in the cost of debt calculation would increase by approximately $300,000. This has the nominal impact of increasing Staff's cost of debt by 1 basis point, as is shown on Schedule CNF-2RB.

VII. <u>CAPITAL STRUCTURE AND COST OF CAPITAL</u>

Q. WHAT WAS THE ORIGINAL COST OF CAPITAL REQUESTED BY THE COMPANY?

A. The Company requested an 8.67% cost of capital, as indicated on Standard Filing Requirements ("SFR") Schedule D-1.

Q. WHAT IS THE COMPANY'S POSITION AS TO THE APPROPRIATE COST OF CAPITAL?

A. Given Staff's and intervenors' recommendations regarding the treatment of the PWEC assets and other adjustments, my rebuttal testimony updates the cost of capital calculation for APS. After making several corrections for items raised since the filing, a cost of capital of 8.68% is appropriate using Staff's recommendation against the ratebasing of the PWEC assets. The application of these same corrections to the PWEC pro forma adjustment discussed in Mr. Robinson's rebuttal testimony results in an adjusted 8.31% cost of capital if the PWEC assets are ratebased, which is the same cost of capital as in the Application.

Q. PLEASE DESCRIBE THE ADJUSTMENTS THAT APS HAS MADE TO ITS ORIGINAL COST OF CAPITAL REQUEST.

A. The starting point for determining the Company's cost of capital still should be the actual capital structure of APS at the end of the test year. On the Company's Application, that was shown as 49.77% debt and 50.23% equity on SFR Schedule D-1, which is roughly a 50% debt, 50% equity ratio.

Q. DOES THE CAPITAL STRUCTURE REQUIRE ANY ADJUSTMENTS FROM THE ORIGINAL FILING?

A. Yes, it does. As stated in Mr. Robinson's rebuttal testimony, APS agrees with Staff's adjustment to remove capitalized vehicle leases from its rate request. In his schedules, Mr. Robinson removes those leases from rate base, as well as the associated depreciation amount from expenses. Because those leases were treated as debt in the Company's capitalization, that debt must also be removed from the capital structure and the cost of capital calculation as well. The removal of the capitalized vehicle leases reduces the test year debt balance by approximately $19.6 million and is shown in Schedule CNF-2RB.

Q. GIVEN THE ADJUSTMENTS YOU HAVE JUST DESCRIBED, WHAT IS THE APPROPRIATE CAPITAL STRUCTURE TO UTILIZE IN THE COST OF CAPITAL CALCULATION.

A. Using these adjustments, the appropriate end of test year capital structure would be 49.55% debt and 50.45% equity.

Q. PLEASE EXPLAIN ANY ADJUSTMENT YOU HAVE TO THE COST OF DEBT?

A. First, there were two errors in the original calculation. Those amounted to approximately $536,000 of overstated interest expense during the test year. In addition, to accurately and consistently remove the capitalized vehicle leases from the Company's request, approximately $1.1 million of related interest expense must be removed from the cost of debt calculation. Lastly, test year interest expense must be increased by $281,000 to reflect the amortization of the debt associated with the adjustment to net losses on reacquired debt. The resulting test-year interest expense is $122,960,000. Given a debt balance of $2,120,401,000, this equates to a 5.80% cost of debt.

Q. WOULD YOU PLEASE SUMMARIZE THE COMPANY'S COST OF CAPITAL REQUEST.

A. Yes. The following table illustrates the calculation of the 8.68% cost of capital after applying the adjustments I discussed earlier.

	Weight	**Cost**	**Weighted Cost**
Long-term Debt	49.55%	5.80%	2.87%
Common Equity	50.45%	11.50%	5.80%
Cost of Capital			8.68%

The cost of capital calculation is summarized in Schedule CNF-2RB.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Tax Adjustments

Description of Adjustment	Action	Difference from Filing (Total Company)
Property Tax Adjustments		
(1) Prior period payment for settlement of tribal taxes for 2001	Accepted adjustment proposed by ACC Staff (Dittmer)	($3,793,668)
(2) Adjustment to property taxes reflect updated assessed values of APS	Adjustment proposed by APS in rebuttal testimony	($283,059)
	Total Property Tax (1)	($4,076,727)
Income Tax Adjustments		
(1) State income tax credits	Accepted adjustment proposed by ACC Staff (Dittmer)	($1,540,000)
(2) Meals & entertainment permanent difference	Accepted adjustment proposed by ACC Staff (Dittmer)	$533,000
	Total Income Tax (2)	($1,007,000)

(1) Difference from SFR Schedule C-2, pro forma number (24), column (UU).
(2) Difference from SFR Schedule C-2, total income statement adjustments, column (CCC).

Cost of Capital Calculation

	As Filed (1)	Remove Vehicle Leases	Subtotal	Corrections	Subtotal	Net Loss on Reacquired Debt	Total
Interest Expense	124,315	(1,130)	123,185	(536)	122,649	281	122,930
Debt	2,139,955	(19,554)	2,120,401		2,120,401		2,120,401
Cost of Debt	5.81%		5.81%		5.78%		5.80%
Equity	2,159,312		2,159,312		2,159,312		2,159,312
Cost of Equity	11.50%		11.50%		11.50%		11.50%
Debt Ratio	49.77%		49.55%		49.55%		49.55%
Equity Ratio	50.23%		50.45%		50.45%		50.45%
Cost of Capital	8.67%		8.68%		8.67%		8.68%

(1) See "End of Test Year 12/31/02" amounts from SFR Schedules D-1 and D-2.

APS-6R

EXHIBIT
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REBUTTAL TESTIMONY OF AJIT P. BHATTI

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

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REBUTTAL TESTIMONY OF AJIT P. BHATTI
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Ajit P. Bhatti. I am Vice President of Resource Planning for Arizona Public Service Company ("APS" or "Company"). My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I first respond to various criticisms by Utilities Commission Staff ("Staff) and intervenors of both the resource planning process that was undertaken beginning in 1998 and the specific resource plan then selected, which plan resulted in the construction of the Pinnacle West Energy Corporation ("PWEC") Arizona generation discussed in my Direct Testimony. Second, I will provide the Arizona Corporation Commission ("Commission") a series of analyses estimating the "prospective value" or current "market value" of these assets and comparing that value to the option proposed by APS in this proceeding, which is to acquire the assets from PWEC at net book value as of the date of transfer and to include them in the Company's rate-base under the traditional regulatory principles described by myself, as well as APS witnesses Steven Wheeler and Dr. William Hieronymus. Third, I will respond to specific factual assertions made by certain of the Staff and intervenor witnesses concerning either the need for or the benefits anticipated from acquiring the PWEC generating assets and conversely, the cost to APS customers of foregoing the benefits anticipated during the last two years of the APS/PWEC Track B agreement. And last, I answer the questions asked by Commissioner Gleason in his letter dated December 16, 2003.

II. SUMMARY

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. Yes. Staff witness Harvey Salgo and Residential Utility Consumer Office ("RUCO") witness David Schlissel offer two principal criticisms of the resource planning process I described at length in my Direct Testimony. First, Mr. Salgo contends that the economic analysis conducted during the original planning phase did not demonstrate that the PWEC Arizona assets represented the best or "optimal" incremental addition to the Company's resource mix. Second, both Mr. Schlissel and Mr. Salgo opine that on an APS-only basis, it would have been appropriate for APS to have constructed more combustion turbine ("CT") capacity and less combined-cycle capacity. Neither criticism is valid.

Dr. Joseph Kalt, a witness for the Arizona Competitive Power Alliance ("ACPA") contends that the PWEC units were constructed to compete in the wholesale market and contribute to the profits of PWEC. Both contentions are true, but neither contention is inconsistent with the fact that these units were planned and constructed to meet anticipated APS needs nor does it affect the irrefutable conclusion from my analyses that these units represent significant value to our customers compared to other alternatives, including purchasing power from Dr. Kalt's clients.

As I explained in my Direct Testimony, the generation planning conducted during the 1998-2001 time frame was based both on a rigorous planning process and state-of-the-art economic modeling techniques, including the GE MAPS regional dispatch model, which produced both discounted cash flow ("DCF") and present value revenue requirements/busbar cost ($/MWh) evaluations for each of the PWEC assets. In each instance, the economic evaluation of the individual PWEC units took into consideration how that unit would fit into the existing portfolio of APS generation just as would have been the case had such an analysis been undertaken in the absence of the then-anticipated divestiture of APS generation to PWEC. Thus, Mr. Salgo appears to be basing his conclusion that the resource planning process was not, in Dr. Hieronymus' words, "APS-centric," less on any specific criticism of either the process itself or the economic modeling tools used, but on the alleged lack of contemporaneous documentation that reflects the analysis of the PWEC units from the perspective of a vertically-integrated and cost-of-service regulated electric utility. Such a conclusion, which again did not reflect any rigorous economic analysis of then-available alternatives, is neither fair nor accurate.

Because the 1999 APS Settlement and the Electric Competition Rules required APS generation to be divested to PWEC, it is not reasonable for Staff to expect that resource planning documents from 1998-2001 would reflect an analysis of new generation from the perspective of APS as a vertically-integrated utility. PWEC was created to be a GENCO affiliate of APS in conformance with the Commission's electric restructuring program, and the contemporaneous PWEC planning documents are those of a "GENCO" rather than a traditional utility. However, this is more an argument about the "packaging" of the analyses than substantive differences in either approach or result. This is because the fundamental evaluative methods, as well as the conclusions of that GENCO analysis, would also hold for a vertically-integrated utility – namely that the PWEC assets represented the best incremental resource addition then available, whether for PWEC as a GENCO or for APS as a vertically-integrated electric utility. Moreover, alternative technologies and fuel sources were considered and rejected in favor of what our studies indicated was a more economic resource (the PWEC assets) and one which would add additional fuel diversity to the existing portfolio of APS generation PWEC was to acquire under terms of the 1999 APS Settlement and the Electric Competition Rules.

The analyses conducted during the planning of the PWEC units concluded that the higher efficiencies and ability to produce off-system margins (from sales of surplus energy) more than off-set the higher capital costs of combined-cycle gas units. Thus, such units can meet both reliability needs and provide economical energy for APS customers and the broader wholesale market. I believe that these original planning studies are the best evidence that our decision to construct combined-cycle units at West Phoenix and Redhawk rather than CTs was prudent even assuming the latter could have been permitted in Phoenix under existing air quality regulations. However, in my Rebuttal Testimony, I again examine this issue with the benefit of hindsight and once again conclude that the original decision to build combined-cycle units remains as valid today as it was then, with the postulated substitution of CTs resulting in <u>additional</u> costs (present value) to APS customers of between $300 million and $600 million as compared to the anticipated cost of rate-basing the PWEC assets.

In his Rebuttal Testimony, Mr. Wheeler suggests several ways of estimating the "market value," or what Mr. Salgo terms the "prospective value" of the PWEC assets. These include DCF, "replacement cost," "reconstruction cost," and "comparable sales." I address the first three estimation techniques in my Rebuttal Testimony, while Dr. Hieronymus will discuss the use (and potential misuse) of "comparable sales."

Using DCF and alternative market price simulations, I have estimated the "market value" as of January 1, 2005 of the PWEC assets – both individually and as a "package." I have also reflected the impact of terminating the PWEC "Track B" contracts as of the same date. My study indicates that the "market value" of the PWEC assets (even after recognition of all APS/PWEC Track B contract benefits) exceeds their book or rate-base cost by as much as $1 billion and is not less than such rate-base cost under any set of reasonable DCF assumptions as depicted in Table 1 below.

Table 1

PWEC Generation Market Value – DCF Model Results

With Track B in 2005-2006

1/1/2005 (Millions)

	APS Base (Genco)	APS Requested	ACC Staff Proposed	RUCO Proposed	Ratebase
MARKET PRICES	**7.00% COD 11.50% ROE**	**5.76% COD 11.50% ROE**	**5.82% COD 9.00% ROE**	**5.72% COD 9.50% ROE**	**Cost as of 1/1/2005**
1 Fundamental	928	970	1,177	1,135	870
2 Cyclical	1,096	1,144	1,376	1,329	870
3 Underbuild	1,621	1,690	1,955	1,904	870

I would also add that if the Commission determines that current market value of generation should be used for ratemaking purposes, my DCF analysis estimates the market value of APS' existing generation to be somewhere between $4.2 billion and $5.9 billion, rather than the approximately $2.0 billion net book value reflected in the Company's present rate filing.

I next provide an estimate of "market value" based on what Mr. Wheeler describes as "replacement cost," that is, what it would cost APS to replace (functionally, not necessarily by the same identical means) the capacity and energy provided by the PWEC generation under a number of plausible resource expansion scenarios. Another way of expressing this sort of comparative analysis is to characterize it as the "customer benefit" from rate-basing the PWEC assets in comparison with an alternative supply expansion option. In all, I analyzed 18 discrete generation expansion plan alternatives. These included asset-backed and market-based plans or combinations of the two. Some of these scenarios were provided by Staff during the discovery phase of this proceeding, while others were devised by APS Generation Planning. All of those scenarios involving new construction make optimistic assumptions about the ease of siting and financing new construction that likely undervalue the advantages of acquiring already-sited and constructed units such as the PWEC assets. In all but two of the alternatives, I assume the APS/PWEC Track B contract remains in effect through its term. And in these two instances, I evaluated alternatives to both rate-basing the PWEC units and the APS/PWEC Track B contract. Thus, in comparing these alternatives to our rate-base proposal, I have effectively factored in the actual "cost" to APS in 2005 and 2006 of early termination of the PWEC Track B contract under such rate-base proposal, just as I did for my DCF analyses.

Despite these biases against the "PWEC in rate-base" option, the replacement cost studies, when properly done, show no material advantage to any alternative and, in fact, a <u>disadvantage</u> (compared to rate-basing the PWEC assets) in 17 of the 18 alternatives, even though many of these alternatives, including that single alternative showing a miniscule cost to customers under the rate-base proposal, make highly optimistic assumptions about ease of siting and the ability of APS to seamlessly finance and execute a massive construction program. And all the cases show even greater benefits from rate-basing the PWEC assets at any lower cost of capital, and especially the lower costs of capital recommended by Staff and intervenors. Again, this means that based on replacement cost, as measured by the various plausible alternatives to the PWEC assets, the "market value" or "prospective value" of these assets to APS customers, that is the customer benefit, exceeds their rate-base cost as indicated by the results in Table 2 below.

Table 2

Replacement Cost Summary Based on Using Alternative Resource Plans
PWEC Asset Revenue Requirements vs Alternative Resource Plans

		Benefit / (Cost) (2005-2032) NPV - $Millions	
RESOURCE ALTERNATIVE		At Requested Cost of Capital	Original Study
Alternative	**1**	463.2	463.2
Alternative	**2**	622.0	622.0
Alternative	**3**	366.3	366.3
Alternative	**4**	(37.4)	(42.5)
Alternative	**5**	145.1	169.1
Alternative	**6**	2478.8	2440.0
Alternative	**7**	2688.5	2649.8
Alternative	**8**	37.8	(0.9)
Alternative	**9**	72.5	33.8
Alternative	**10**	60.5	21.8
Alternative	**11**	54.5	15.8
Alternative	**12**	133.4	94.7

Staff witness Salgo also presented a revenue requirements comparison of the cost of rate-basing the PWEC assets to one of the alternative generation expansion scenarios described above. Although using an example based on Alternative 4 above, the alternative least favorable to the rate-base option, he nonetheless initially showed benefits from rate-basing the PWEC assets. Mr. Salgo then hypothesizes that such savings could be offset by assumed increases in turbine efficiency if the APS/PWEC Track B capacity were replaced in 2007 with newer units. Mr. Salgo's analysis is flawed in several key respects. These include his misallocation of the APS/PWEC Track B contract costs to the second half of 2004, the assumption both that higher efficiency turbines (even if they actually exist in 2007) could be ordered today in time for inclusion in 2007 generation and that such turbines would not carry with them substantially higher prices, and the use of cost-of-capital and depreciation rates inconsistent with Staff's cost-of-capital and depreciation rate recommendations in this proceeding. Mr. Salgo's alternative to rate-basing the PWEC assets is a fundamentally unexecutable plan, with the hypothesized new construction necessarily replaced by one or more PPAs. Based on the offers received by APS for such PPAs, the rate-base option is clearly more economic.

Mr. Salgo further recommends that there be an independent party "due diligence" of the condition and operation of the PWEC plants. This is unnecessary given: (1) the plants' history; (2) the fact that they are already operated by current or former APS personnel; and (3) the plants' long-term maintenance agreements with their manufacturers.

All but six of the above-referenced 18 alternative generation supply expansion scenarios were produced by a combination of economic modeling and revenue requirements/busbar comparisons with the various different asset and market purchase mixes. But although our modeling tools are quite sophisticated and have proven valuable planning and evaluative tools, some may assert that no simulation can capture all the dynamics of an actual competitive solicitation. Indeed, Staff and intervenor witnesses in their testimony have raised the issue of the Company's recent request for proposals ("RFP"), which was first interjected into this proceeding by the ACPA. Although reluctant to engage these attacks, for the reasons also discussed by Mr. Wheeler, we cannot allow such a failure to respond be misinterpreted by the Commission to the ultimate detriment of customers. Therefore, and with great care taken to preserve the identity and specific bid terms of individual bidders, I substituted our analysis of the more favorably-priced long-term purchased power offers for the GE MAPS market price simulation in an additional DCF estimate of "market value" or "prospective value" of the PWEC assets. This additional DCF estimate placed the value of PWEC assets to be between $87 million (APS cost of capital) and $427 million (Staff cost of capital) greater than their rate-base cost as can be determined from Table 3 below.

Table 3

PWEC Generation Market Value - DCF Model Results Using RFP Data
With Track B in 2005-2006
1/1/2005 (Millions)

	MARKET PRICES	APS Base (Genco) 7.00% COD 11.50% ROE	APS Requested 5.76% COD 11.50% ROE	ACC Staff Proposed 5.82% COD 9.00% ROE	RUCO Proposed 5.72% COD 9.50% ROE	Ratebase Cost as of 1/1/2005
1	Average of Four Lowest PPA's	1,034	1,081	1,297	1,254	870
2	Average of Three PPA's (Comb. #1)	1,017	1,062	1,278	1,235	870
3	Average of Three PPA's (Comb. #2)	1,025	1,071	1,281	1,240	870
4	Representation of PPA	917	957	1,153	1,113	870

I also compared six alternative supply expansion scenarios based on entering into one or more of such PPAs. Again, and without divulging the specifics of any one of the proposals received by the Company, I have been able to make certain revenue requirements/busbar comparisons between the PPA offers presented and the cost to APS customers of the PWEC rate-basing proposal. These showed present value revenue requirements savings to APS customers from the PWEC rate-base proposal of between $312 million and $893 million as shown in Table 4 below.

Table 4

Replacement Cost Summary Based on Using RFP Data
PWEC Asset Revenue Requirements
vs Alternative Resource Plans Based on RFP Data

Prospective Alternatives	2005-2032 [(1)] Benefit NPV $Million
Alternative 13	312.2
Alternative 14	457.3
Alternative 15	511.0
Alternative 16	362.1
Alternative 17	784.1
Alternative 18	893.3

(1) Value above rate base cost.

Overall, I must conclude that: (1) the PPAs offered were uniformly more costly to APS customers than was the rate-basing (of PWEC generation) alternative, even before allowing for any additional credit support the Company would have to purchase to hedge against the default risk inherent in long-term PPAs; (2) the generation assets actually offered for purchase, although in fact more expensive to customers than the PWEC assets on a levelized per MWh basis, were not comparable in either amount or type with the PWEC assets, and thus should be excluded from any analysis of replacement cost; and (3) the PPAs were priced in a manner consistent with the GE MAPS market simulation analyses used both in the planning of the PWEC assets and in my current DCF and replacement cost analyses.

APS presented a form of reconstruction cost new ("RCN") calculation in Mr. Wheeler's Direct Testimony, which came from my calculation of the benefit APS customers would receive from getting a somewhat older and already partially-depreciated set of PWEC units compared to a new unit of the same kind. In my Rebuttal Testimony, I present a more comprehensive RCN analysis showing a comparative present value benefit of between $196 million and $248 million from the Company's rate-base proposal. This is another way of saying that the "market value" or "prospective value" of the PWEC units to APS and its customers is significantly more than their rate-base cost.

Although finding that the rate-basing of the PWEC generation provides customer benefit on a present value basis, RUCO witness Schlissel expresses the concern that the "cross-over" point (that is, when the present value to APS customers of the rate-base alternative becomes a positive number) is too far into the future, thus leading him to ignore the customer benefit and recommend against rate-basing the PWEC assets. However, Mr. Schlissel's "cross-over" analysis contains several significant errors and inconsistent assumptions that result in "cross-over" points that appear to come later in time than are actually the case. Indeed, under RUCO's cost of capital recommendations, that "cross-over" occurs in the first year the PWEC assets are in rate-base. Moreover, even if his analysis had been correct, Mr. Schlissel would elevate and emphasize short-term rate considerations at the expense of admitted long-term customer benefits.

Next, I take issue with both the calculation of and the conclusions drawn about the extent and consequences of vertical integration from a graph attached to the testimony of Dr. Kalt (Exhibit JPK-10). Rather than being the most vertically-integrated utility in the West, APS will be much more towards the middle of the pack, even with the PWEC generation. Moreover, the consequences to the utilities and their customers of being overly exposed to the market have been devastating, with rate increases through 2002 ranging from between 37% to 50% and bankrupt or near bankrupt utilities.

In response to a series of questions from Commission Gleason, I testify that APS uses, for planning purposes, a definition of "base-load," "intermediate," and "peaking" resources that is in line with standard electric industry use of those terms. Specifically, base-load units are those expected to have capacity factors (that is, actual output in MWh as a percentage of their theoretical maximum output assuming 100% unit availability and continuous "24/7" operation at such maximum output throughout the entire year) of 50% or more. Intermediate units can be expected to have capacity factors in the 20%-50% range, while peaking units generally operate at capacity factors under 20%. Customer load profile, unit availability, marginal fuel (usually natural gas) cost, and market price all affect individual unit capacity factors. Units also will tend to change their "duty-cycle" (that is, increase and then drop in capacity factor) as load growth first increases their utilization and then, with age, they become relatively less efficient and more costly to maintain at a given level of performance. Those caveats being made, all of the Company's nuclear and coal generation is and will remain base-load generation for the foreseeable future. APS existing gas-fired combined-cycle generation and the PWEC combined-cycle generation, if acquired by APS, are intermediate to base-load, with PWEC generation being closer to base-load because it is more efficient than the older APS units. APS' older gas-fired steam units will be either intermediate or peaking, depending on whether the PWEC units are acquired by APS. The APS and PWEC CTs are peaking units irrespective of whether APS acquires the other PWEC generation.

APS is capacity-short with or without the PWEC assets, and the problem only becomes more alarming over time. Also, it has and will have in the future some excess energy to sell during off-peak seasons both with and without the PWEC assets. This has allowed our customers to benefit for many years from the margins earned on off-system sales and must be considered by any planner in evaluating the economics of alternative resources. However, the "without" scenario leaves APS and its customers much more exposed to price volatility in both the natural gas and power markets and also carries with it the potential for degraded reliability. The consequences of such exposure is discussed and quantified in my Rebuttal Testimony and is also addressed in the rebuttal of other Company witnesses

III. "APS-CENTRIC" RESOURCE PLANNING

Q. STAFF WITNESS HARVEY SALGO STATES THAT TO DEMONSTRATE ITS RESOURCE PLANNING PRUDENCE, APS SHOULD BE REQUIRED TO PROVIDE "PLANNING DOCUMENTS PREPARED AT THE TIME THAT SHOW THAT THE PWEC INVESTMENT WAS OPTIMAL FOR APS [SALGO TESTIMONY AT 9]." IF READ LITERALLY, IS THAT A REASONABLE REQUEST?

A. No, for several reasons.

Q. PLEASE EXPLAIN.

A. First, as discussed in the rebuttal of Mr. Wheeler and Dr. Hieronymus, prudence does not demand perfection, which is what Mr. Salgo's use of the word "optimal" implies to me. Neither does it require that APS conduct analyses of <u>every</u> theoretically-possible supply-side or demand-side alternative before its actions can be deemed prudent. That is a recipe for <u>in</u>action. It also ignores the fact that it was the Commission's decision to first end integrated resource planning ("IRP") of the kind suggested by Mr. Salgo and also its decision not to reinstate IRP as part of the Track A Order. I would further add APS had implemented those demand-side management ("DSM") programs found economic by Commission Staff prior to the planning of the PWEC units, something reflected in the demand and energy forecasts for the Company. The Commission subsequently reduced funding for APS DSM programs in 1999.

Mr. Salgo's second point may be more semantics than substance. As I noted in my Direct Testimony, the PWEC assets were planned following the jump in APS demand in the summer of 1998. By that time, the Commission had mandated divestiture as part of its Electric Competition Rules. Looking at future resource additions as if APS were to continue as a vertically-integrated entity would have been contrary to the policy explicitly set forth in such Rules. Not surprisingly, our analyses of the PWEC units focused on the competitiveness in the wholesale market of their anticipated costs (the busbar cost studies) and their anticipated life-cycle profitability (the internal rate of return or "IRR" studies). These were the studies discussed in my Direct Testimony and provided to Staff and others as part of my work papers. To my knowledge, no witness has criticized or even questioned the accuracy of these analyses nor contested the conclusions drawn from the earlier studies. However, and although not presented or labeled as such for the reason discussed above, these same studies also demonstrated that the PWEC assets would have been the appropriate incremental resource for APS had we assumed that APS was to remain a vertically-integrated utility.

The busbar/revenue requirements cost studies are essentially a present value cost-of-service revenue requirements analysis with a different name. Indeed, the term "revenue requirements" is often used interchangeably with busbar cost as a methodology to compare resource alternatives. This is precisely what we used to do prior to the Electric Competition Rules' divestiture requirement and what we do today in the aftermath of the Track A Order.

Similarly, and again from the perspective of a vertically-integrated APS, an IRR study reflects that an incremental generation resource produces benefits for APS native load customers in three ways: (1) it improves the overall operating efficiency of the entire portfolio by displacing less efficient generation in the dispatch order and adds to fuel diversity; (2) it replaces the need to acquire alternative incremental resources from the market; and (3) it provides an opportunity to generate incremental margins from off-system sales. IRR captures all three of these benefits, which is why I indicated in my Direct Testimony that a project having an IRR greater than the APS cost of capital means the project will produce net customer benefits under cost-of-service regulation. Also, I would note that the use of IRR to rank various resource options is directly related to the DCF evaluation method I discussed in my Summary and in the next section of my Rebuttal Testimony. The only difference is that IRR determines the profitability of a given investment (or compares the profitability of multiple investments) given its anticipated cash flows and expresses it as a percentage return. DCF looks at those same cash flows and discounts them into a present value, with the asset having the higher present value representing the more economical choice (under cost-of-service regulation) or, alternatively, the more profitable choice (under deregulation).

Q. DID YOU ANALYZE OTHER RESOURCE OPTIONS TO THE CONSTRUCTION OF THE PWEC ASSETS?

A. Yes. As also discussed in my Direct Testimony, we began looking at resource options as long ago as 1995, when our RFP indicated that the only way we could secure a long-term PPA was for the potential seller to construct new generation. We also specifically looked at differing generation construction options, including coal and simple-cycle gas turbines. For example, in June of 1997, the APS Generation Planning Department, in collaboration with the Engineering

Department, prepared a comprehensive "Generation Technology Assessment" report. This report reflected our analysis of the newer, as well as other more proven, gas-fired generation technologies then available. A total of 12 different types of gas-fired generation were studied. And even during the early stages of construction of all but West Phoenix CC-4, which could not have been constructed as anything other than a gas-fired unit due to environmental concerns, we re-examined our choice of technology, including a look at coal and nuclear. These other technologies proved less economic than the ongoing PWEC construction program.

In summary, our studies consistently indicated that the efficiency gains from the new generation of combined-cycle gas generation more than off-set the higher capital costs as compared to simple-cycle CTs and showed this gas technology likely to be more cost-effective than other generation technologies such as coal or nuclear. And as I also indicated in my Direct Testimony and have repeated here, the addition of gas-fired generation to the existing portfolio of APS generation made sense from a fuel diversity standpoint.

Q. DO OTHER STAFF AND INTERVENOR WITNESSES TAKE EXCEPTION TO THE STATEMENT THAT THE PWEC ASSETS WERE BUILT TO SERVE APS?

A. Yes. Mr. Davis and Dr. Hieronymus address those contentions, although as the person who planned each of the PWEC Arizona assets, there is no question that these plants were constructed first and foremost to serve APS needs. But, the only portion of Staff and intervenor testimony that arguably would go to resource planning prudence are the statements by Mr. Schlissel that APS would, on a stand-alone basis, have constructed fewer combined-cycle units and more CTs (Schlissel Testimony at 22) and those by Mr. Salgo of the same general nature (Salgo Testimony at 8). My earlier Rebuttal Testimony in this same Section discusses the economic evaluation of these alternatives and how the higher efficiencies of the former off-set its higher capital costs both through displacement of higher cost generation used to serve native load and by off-system sales. The fact that PWEC re-evaluated the economics of Redhawk 3 and 4 in late 2001 as CTs does not indicate that Redhawk 1 and 2, let alone West Phoenix CC-5, would have been constructed as CTs had they been constructed at APS.

Q. DOESN'T DR. KALT CONTEND THAT THE PWEC UNITS WERE CONSTRUCTED WITH THE EXPECTATION THAT THEY WOULD SELL INTO THE WHOLESALE MARKET AND WOULD BE PROFITABLE AT THEN ANTICIPATED MARKET PRICES (KALT TESTIMONY AT 29-31). DO YOU AGREE?

A. I agree that the PWEC assets were expected to be profitable over time. I also agree that, because PWEC would have no retail customers, its sales would have necessarily been into the wholesale market. And, as is testified to by Mr. Davis, sales to APS, whether they were from PWEC, Pinnacle West or a non-affiliated supplier, were anticipated to be at some measure of market price. None of this has anything to do with whether our resource planning was "APS-centric" or whether the PWEC Arizona assets were constructed to assure that APS would have access to reliable and economical sources of electricity.

Q. DOES DR. KALT ALSO MAKE THE SAME CONTENTION AS RUCO WITNESS SCHLISSEL AND STAFF WITNESS SALGO CONCERNING THE CONSTRUCTION OF CT UNITS BEING MORE IN LINE WITH APS NEEDS THAN THE PWEC COMBINED-CYCLE PLANTS?

A. Yes. And he is wrong for the same reasons as are Mr. Schlissel and Mr. Salgo.

Q. DID YOU CONDUCT A RETROSPECTIVE ANALYSIS TO DETERMINE WHETHER THE CONSTRUCTION OF ADDITIONAL CTS IN SUBSTITUTION FOR ONE OR MORE OF THE PWEC COMBINED-CYCLE UNITS WOULD HAVE PROVEN MORE ECONOMICAL FOR APS CUSTOMERS.

A. Yes. In fact, as shown in Schedule AB-1RB, I conducted a series of such analyses. The first (Alternative A) assumes that 50% of the Redhawk Units 1 and 2 capacity had been constructed as CTs using EA-type turbines and the other 50% using LM6000 turbines. Without getting into a tutorial on the subject of simple-cycle turbine technology, suffice it to say that as of 1999, the General Electric EA and LM6000 turbines were the turbines of choice for simple-cycle applications throughout the industry. The EA was cheaper to buy or build and had a longer track record of performance. The LM6000 was more efficient and had a proven emissions control technology that made it easier to site, especially in urban areas. This is not to say that other manufacturers' turbine configurations are "bad" or even that one General Electric turbine is "better" than the other, only that they have different costs and operating characteristics and that there are usually trade-offs between them. This alternative plan increases costs to APS customers, compared to the actual PWEC assets, by some $311.7 million.

The second alternative replaced all the Redhawk capacity in 2002 with LM6000 machines. As in the first scenario, I left West Phoenix CC-4 and CC-5 as they were built by PWEC. Alternative B resulted in higher costs to APS customers to the tune of $402.3 million. Since adding another 50% of Redhawk capacity as LM6000 CT capacity increased present value costs by $90.6 million compared to Alternative A, one can also deduce that redoing Alternative A with only EA machines would have reduced the additional cost to customers of that option by another $90.6 million, or from $311.7 million to $221.1 million – but still <u>far</u> more costly than the resource plan actually implemented by PWEC for APS.

Alternative C is the same as Alternative A except I replaced West Phoenix CC-4 and CC-5 with LM6000 CTs in 2001 and 2003, respectively. I am not convinced that even the LM6000 could have been permitted here in the Valley despite its proven SCR emissions control technology, but I am sure it is one of the few, if not the only machine of that time period that might possibly have been approved by environmental officials for use at West Phoenix, and thus I did not study the use of any EA units at that location. Given the steep additional price tag of Alternative C, some $620 million more than the PWEC assets, even such an unrealistic assumption (substituting all EA machines for all of PWEC's combined-cycle units) would not have put much of a dent into these significantly higher costs for the resource plans hypothesized by Mr. Schlissel, Mr. Salgo and Dr. Kalt.

Q. IS SUCH A RETROSPECTIVE ANALYSIS A TRUE MEASURE OF THE COMPANY'S PLANNING PRUDENCE?

A. Hindsight is not appropriate when evaluating the original prudence of a utility's actions. The fact that even in such a hindsight review, the PWEC assets again prove to be the correct choice does not change the Company's fundamental objection to the concept of using hindsight to judge the prudence of our foresight.

IV. MARKET VALUE OF THE PWEC ASSETS

A. General

Q. WHY ARE YOU PRESENTING "MARKET VALUE" EVIDENCE?

A. APS continues to believe the traditional considerations of planning prudence, etc., should drive the inclusion of assets in rate-base. However, several witnesses have proposed that the acquisition of the PWEC assets be viewed from the standpoint of their "prospective value" to APS in providing customer benefit, that is, their "market value."

Q. WHAT POTENTIAL INDICATORS OF CURRENT MARKET VALUE DID YOU LOOK AT IN RESPONSE TO THE TESTIMONY OF STAFF WITNESS SALGO (SALGO TESTIMONY AT 12-13), STAFF WINTESS JARESS (JARESS TESTIMONY AT 1-3) AND INTERVNOR WITNESSES, SCHLISSEL (SCHLISSEL TESTIMONY AT 9), KALT (KALT TESTIMONY AT 6-7 AND 26) AND TRANEN (TRANEN TESTIMONY AT 17)?

A. Although Mr. Wheeler's original Direct Testimony (Wheeler Direct Testimony at 19) provided a manner of comparison of the PWEC units with the cost of a new combined-cycle generator, which is what Mr. Wheeler describes in his Rebuttal Testimony as "reconstruction cost new" evidence of "market value," neither I nor other APS witnesses believed that "market value," or what Mr. Salgo calls "prospective value," was at issue in these proceedings for the reasons also discussed at length by Mr. Wheeler in his Rebuttal Testimony.

But, after reading the Staff and intervenor testimony, and in light of the ACPA's December 19, 2003 Motion, which interjected the Company's December 3, 2003 RFP as an issue in this proceeding, I decided to expand upon the original RCN analysis as well as examining other potential means of estimating "market value" or the "prospective value" of the PWEC assets to APS customers. I say "estimating" because there is no 100% objective means of determining "market value" in the same way as we can an asset's book value. These additional means include: DCF; replacement cost; reconstruction cost new; and "comparable sales." DCF is more of a pure "market value" methodology since it can examine either a single asset or a group of assets without necessarily comparing the asset(s) to specific alternatives. Replacement cost necessarily is a comparative analysis of competing options using the present value of their respective cost to customers to compare or rank the options. Reproduction cost new is simply a technology-specific example of replacement cost. In addition to my DCF, replacement cost and reproduction cost new studies, the Company asked Dr. Hieronymus to look at "comparable sales." I put this last term in quotes because often there is not a sufficient population of truly "comparable sales" and, in such instances, we are faced with the subjective task of attempting to identify each of the ways this or that sale of a generating plant is <u>not</u> "comparable" to the proposed acquisition and rate-basing of the PWEC assets and then assigning some dollar value to each "non-comparable" factor.

B. DCF

Q. PLEASE DESCRIBE YOUR DCF ANALYSIS OF MARKET VALUE.

A. The basic premise is the same as for an IRR analysis, which I discuss at length in my Direct Testimony. However instead of determining the life-cycle market return on a specified level of capital investment, we capitalize the present value of the stream of anticipated margins from the asset being analyzed at market prices. I note that this is the same methodology discussed by Staff witness Linda Jaress in her Supplemental Testimony at page 1. It is also consistent with Staff witness Lee Smith's observations about the need to examine the market value of an asset over its entire life rather than for some significantly shorter period of time (Smith Testimony at 15-17).

Q. WHAT WERE THE MOST CRITICAL ASSUMPTIONS TO YOUR DCF ANALYSIS?

A. There are two major variables to any DCF valuation. One is the future net revenue streams, which in this case means future market prices for the power generated from the individual PWEC units less their costs, which costs I took directly from the APS 2003 Long-Range Forecast ("LRF"). It was this LRF that was also used to determine the revenue requirements from rate-basing the PWEC units that serves as the "bogey" against which I evaluate alternative resource expansion scenarios under the "Replacement Cost" subsection of my Rebuttal Testimony on "market value" or "prospective value" of the PWEC assets. The second major variable is the rate of return or cost of capital assumed for both calculating the cost of rate-basing the PWEC units under cost-of-service pricing and for discounting the net revenue stream from market-based sales. To test the robustness of my analyses, I used varying capital costs, reflecting the broad range of recommendations being made in this case and also reflecting the somewhat higher cost of capital assumptions used in my Direct Testimony.

I further examined seven different market scenarios. Three were GE MAPS simulations reflecting different market structure assumptions that I have called: (1) fundamental; (2) cyclical; and (3) under-build. I will explain each of these market structure assumptions in a moment.

In addition, the results of the recent Company RFP were utilized as a second source of data on long-run market prices in the four other scenarios. Specifically, I used various combinations of the bids received as well as a computer-generated representation of a PPA priced at the low end of bids received. I will discuss the results of this aspect of my DCF study in a separate part of my Rebuttal Testimony.

Q. COULD YOU EXPLAIN THE DIFFERENCES BETWEEN THE THREE DIFFERENT SIMULATED MARKET SCENARIOS?

A. All three of the purely simulated market scenarios were modeled using the GE MAPS program discussed in my Direct Testimony. This is the same modeling program utilized in deriving the market price numbers in Mr. Schlissel's and Mr. Salgo's testimonies. The "fundamental" scenario creates a market price tracking the long-run marginal cost ("LRMC") of generation, which is the price at which competitive markets are in equilibrium. Under the "cyclical" scenario, it is recognized that markets rarely adjust to changes in supply and demand in a seamless and equally-timely fashion. Alternate "boom" and "bust" cycles result from first under-building and then over-building of new generation. The "under-build" scenario assumes that the present financial difficulties experienced by merchant generators as an industry and the huge losses experienced by debt and equity investors in that segment, lead to a longer "moratorium" on new construction this decade than would otherwise be indicated by either the fundamental or cyclical scenarios. Thus, the next "boom" for those generators that survive the present "bust" would last a few years longer. However, beginning in 2011, generation expansion returns to the normal construction cycles modeled under the cyclical market structure.

Of the three market modeling scenarios, the cyclical assumption more closely mirrors the actual experience of the industry. It also better captures the timing issue, which relates not to how high market prices are likely to go, but when they might reach that level – an important consideration in determining the present value of future revenue streams from a present-day asset. Because we are closer to the next "boom" than to the last "bust," the cyclical market scenario provides "market values" that are above those produced by the "fundamental" scenario but well below those of the "under-build" market.

Q. WHAT DOES YOUR DCF STUDY INDICATE?

A. The study results are shown in Schedule AB-2RB. As you can see, I have matrixed the results for the differing costs of capital and market structure scenarios. At the Company's requested cost of capital and considering the cost to APS of terminating the APS/PWEC Track B contract at the end of this year, the "market value" of the PWEC assets ranges between $970 million and $2 billion, compared with a "rate-base" value (essentially book value less deferred taxes) of $870 million as of year end 2004, which now appears the earliest that such assets could be effectively included in the Company's rate-base. As I indicated above, I believe the cyclical scenario to be the most realistic of the three modeled. It produces a "market value" of between $1.144 billion (APS cost of capital) and $1.376 billion (Staff cost of capital). This market scenario (cyclical) is also consistent with the APS RFP long-term offers received that I discussed in response to a prior question.

Q. WHY DOES THE "MARKET VALUE" OF THE PWEC ASSETS INCREASE AS COST OF CAPITAL DECREASES?

A. Future net revenue streams are discounted less at a lower cost of capital. Thus, the ability of the PWEC assets to shield APS customers from higher market prices in future years is worth more on a present value basis. And, the revenue requirements of rate-basing the PWEC assets are obviously less at a lower cost of capital.

Q. DO EVEN THESE DCF RESULTS LIKELY UNDERSTATE THE "MARKET VALUE" OR "PROSPECTIVE VALUE" OF THE PWEC ASSETS?

A. Yes. All the cost of capital scenarios assume annual pro rata repayments of the underlying debt used to finance the asset such that at the end of the asset's life, all such debt has been retired. This reduces the net cash flow in each year from which the DCF calculation is derived. In reality, there would likely be no repayment of principal until the end of the debt's term, unless it could be refinanced earlier at more reasonable rates, which would be inconsistent with the model's assumption of constant capital costs. If the repayment of principal were placed at the end of the period (that is, in 2032), rather than pro rata each year, it would significantly increase the present value of the net revenue streams under each of the market structure assumptions. The results under this "balloon payment" assumption are also shown in Schedule AB-2RB.

In addition, Staff has recommended significantly longer depreciation lives for the PWEC assets (Majoros Testimony at 15-18 and 70-74). This also has the effect of back-loading some of these assets' costs and increasing their present "market value" or "prospective value." I show the impacts of this additional refinement to the DCF analyses in Schedule AB-3RB.

Q. DID MR. SCHLISSEL'S DCF ANALYSIS ALSO SHOW PWEC ASSET MARKET VALUES IN EXCESS OF BOOK VALUE FOR THE PWEC ASSETS?

A. Yes. I discuss Mr. Schlissel's analysis in a separate section of my Rebuttal Testimony.

Q. DID YOU ALSO DO A DCF MARKET VALUATION OF APS' GENERATION?

A. Yes. To simplify the analysis, we did not model the more extreme scenario of under-build. Using the Company's requested cost of capital and the cyclical market scenario produces a DCF "market value" of over $5.1 billion, increasing to $5.88 billion using Staff's recommended cost of capital. The fundamental scenario would, as it did for the PWEC-only analysis, produce lower "market value" (and the under-build scenario significantly higher "market value"), but its results of between $4.36 billion and $5.0 billion demonstrate that virtually any conceivable analysis would produce "market value" results well above the rate-base value of such generation, which is projected to be $1.5 billion as of January 1, 2005. A summary of results is contained in Schedule AB-4RB.

Q. ARE YOU SUGGESTING THAT THE COMMISSION ADOPT MARKET VALUE OF THE COMPANY'S GENERATING ASSETS AS THE BASIS UPON WHICH TO SET RATES IN THIS PROCEEDING?

A. No, but I agree with Mr. Wheeler that if the Commission adopts such a valuation for the PWEC assets, the methodology (market value) should, if otherwise legal, be consistently applied to the balance of the generation included in APS rate-base. I also made this analysis to refute the contention of Staff witness Lee Smith that PWEC was not harmed by the Commission's decision to halt divestiture of the APS generation to PWEC (Smith Testimony at 11-12). Obviously, my DCF calculation shows that the existing generation of APS would, on a prospective basis, have proven very competitive in the market had divestiture to PWEC taken place.

C. Replacement Cost

Q. PLEASE TELL THE COMMISSION HOW YOU WENT ABOUT DETERMINING THE COST OF ALTERNATIVE SUPPLY PORTFOLIOS THAT COULD FUNCTIONALLY REPLACE THE PWEC ASSETS.

A. I modeled 18 alternative supply options, 16 of which APS designed and two others provided by Commission Staff. Although I will briefly identify these options in my Rebuttal Testimony, a more detailed description of each of the first 12 alternatives is set forth in my Schedule AB-5RB. The remaining six alternative supply expansion scenarios are discussed in a subsequent portion of my Rebuttal Testimony because they are derived from data obtained from our current market solicitation of long-term resources. In two of the cases, which were run in the Spring of 2003, we used preliminary data, but in each other instance, I used the Company's data from the Company's August 2003 Long Range Forecast ("LRF"), which is the most recent APS forecast of retail load, fuel and other operating costs, power prices, etc., through the year 2032, to determine the annual revenue requirements of the specific supply option being analyzed. I also assumed continuation of the APS/PWEC Track B contract in all instances but two since none of these alternative scenarios involved acquiring and rate-basing the PWEC units.

One (Alternative 5) of those two alternatives (which did not reflect the APS/PWEC Track B contract throughout its term) was done in April of 2003 at roughly the same time as the Track B contracts were being finalized and prior to the finalization of the 2003 Long Range Forecast. The other (Alternative 7) was completed in August 2003. These two analyses were done to measure the impact of possible scenarios that were seen as alternatives to both rate-basing of the PWEC assets and to some potential purchases under Track B. Thus, all the scenarios that were compared to just the Company's rate-base proposal included the impact of early termination of the APS/PWEC Track B contract. I will discuss these in more detail later in my Rebuttal Testimony.

Q. YOU INDICATED THAT SOME OF THE ALTERNATIVE PLANS ANALYZED HAD BEEN PROVIDED BY STAFF. DID APS ALSO PROVIDE STAFF WITH THE ANALYSES OF THOSE ALTERNATIVE SUPPLY EXPANSION SCENARIOS FORMULATED BY APS?

A. For seven of the alternatives, yes. These seven scenarios, along with the two scenarios formulated by Staff, were previously provided to Staff during discovery. In preparing my Rebuttal Testimony, I have had the opportunity to review these prior analyses and have discovered that they are in need of certain revisions.

Q. PLEASE EXPLAIN.

A. The two scenarios run earlier in 2003, Alternatives 4 and 5, were run at a cost of capital that assumed a 12% COE, 6.25% debt and a 50/50 capital structure. Alternatives 6 through 12 used the 7% debt and 11.5% COE I previously discussed. At a minimum, these alternatives should reflect no more than our cost of capital recommendation in this proceeding.

Q. WHERE DID THE OTHER NINE ALTERNATIVE SUPPLY EXPANSION SCENARIOS COME FROM?

A. Three of them were additional asset-based programs using various mixes of CT technologies to replace all or some of the PWEC units after expiration of the APS/PWEC Track B contract on October 1, 2006. The other six were PPA alternatives based on the ongoing RFP. I discuss these latter six alternatives in a separate portion of my Rebuttal Testimony.

Q. HOW DID YOU USE YOUR ANALYSES OF THE VARIOUS SUPPLY EXPANSION SCENARIOS TO DETERMINE THE VALUE TO CUSTOMERS OF THE RATE-BASE PROPOSAL?

A. I calculated the present value of the life-cycle revenue requirements under each alternative supply expansion scenario and compared it to the present value of revenue requirements under the base case, which is the acquisition by APS of the PWEC assets at book value and placing them into the Company's rate-base. For this reason, this method of doing comparative analyses is often referred to as the "revenue requirements" method and was commonly used in the type of comparative evaluation of resource options in IRP proceedings. In any event, the range of present value benefits to APS customers from the rate-base option was different for each APS supply expansion option modeled.

Q. PLEASE DESCRIBE THE RESULTS OF YOUR ANALYSES OF THEIR RESPECTIVE REVENUE REQUIREMENTS?

A. Let me first begin with the three new asset-based alternatives. As I indicated previously, these alternatives each involve substituting various types and mixes of CT technologies, including the GE-EA machine used for Saguaro CT-3 as well as the 7FA and LM6000 machines described in an earlier portion of my Rebuttal Testimony. Not surprisingly, given the results of my retrospective analysis of our original decision to construct combined-cycle units, the additional cost to our customers from each of these alternative supply expansion scenarios is high, ranging from over \$366 million to \$622 million.

Alternatives 4 and 5 are the same basic scenarios used by Mr. Salgo and discussed in more detail later in my Rebuttal Testimony. Although Alternative 4 originally showed (2003 present value) benefits (compared to rate-basing the PWEC assets) of \$36 million , those savings were at the 12% COE, 6.25% debt and 50/50 capital cost assumptions. Using the Company's requested cost of capital decreases those customer benefits (from this Alternative compared to rate-basing the PWEC assets) to \$32 million (2003 present value). Staff and RUCO's proposed costs of capital would further reduce Alternative 4's apparent slim advantage. However, this Alternative suffers the same shortcomings as did Witness Salgo's analysis, in that it assumed all the generation shortfall could be constructed in a single year with no significant financing, siting or construction management issues

Alternative 6 is the "market will provide" option, which has APS neither constructing nor buying any new utility-owned generation. Its present value <u>cost</u> is some $2.5 billion greater than the Company's rate-base proposal.

Alternative 7 is another non-asset backed plan, except that market purchases begin in 2005. It would cost APS customers $2.7 billion more than rate-basing the PWEC assets. Although this alternative does not reflect the impact of the Track B contracts in 2005 and 2006, their inclusion would only have reduced the increased cost to APS customers back to the same approximate level as Alternative 6.

Alternative 8 first appeared to be about a statistical push with the rate-base option, showing a tiny cost to the rate-base proposal of less than $1 million. Using the Company's requested cost of capital, the comparison indicates an advantage to the PWEC rate-base option of $38 million. Moreover, in our original running of this Alternative, which was provided by Staff, it was assumed (among other things) that the 7FA type machines could be built inside the Phoenix metropolitan area. That is not possible, at least at the costs also assumed, for environmental reasons. Using LM6000 machines would increase the costs of this alternative supply expansion scenario to above the PWEC rate-basing proposal, even at the higher cost of capital assumed in the original analysis. It also requires a huge construction program to be completed by 2007 but not before. Thus, Alternative 8 is subject to the same problems as Alternative 4.

Alternative 9 was also provided by Staff. It further assumes that the entire bundle of Track B contracts can be replaced by block purchases without moving the market and that at least some of these purchases can be used for reliability must run ("RMR".) Thus, like Alternatives 5 and 8, it is not a practical supply expansion option for the Company. It shows present value cost vs. rate-basing the PWEC assets of just under $73 million using the Company's cost of capital.

Alternative 10 is more phased-in, but still assumes a huge construction program for 2006 and 2007. Moreover, its cost is $61 million higher than the PWEC rate-base proposal presently before the Commission.

Alternative 11 assumes a more reasonable and spaced-out construction program, although still overly-optimistic as to likely future construction costs and siting issues. This alternative also carries with it higher reliance on the market, which further exposes APS customers to its volatility. Its present value cost to APS customers is roughly $55 million more than rate-basing the PWEC assets.

Alternative 12 builds 900 MW of CT capacity by 2006 and then new combined-cycle units at the end of the Track B contracts. This alternative again calls for an accelerated and intensive construction program and, not surprisingly, results in a higher cost to APS customers, amounting to some $133 million in additional revenue requirements as compared to the rate-basing of the PWEC assets.

Q. DO THE CUSTOMER BENEFITS YOU HAVE DISCUSSED ABOVE FULLY MEASURE THE VALUE OF THE PWEC ASSETS?

A. Not necessarily. First of all, I used the Company's requested cost of capital and proposed PWEC asset depreciation rates. The benefits would be higher if a lower cost of capital or if lower PWEC depreciation rates were used for the reasons I explain later. Second, those alternative supply expansion scenarios that substitute CTs for the PWEC combined-cycle assets carry with them increased market risk, both for purchased power and gas as well as increased construction risk. This is because although CTs can cover the capacity short-fall, they can still leave APS and its customers energy-short to the market.

Q. PLEASE EXPLAIN.

A. Because CTs are less efficient than combined-cycle generation, the more such CTs have to operate, the more customers have to pay in disproportionately higher per kWh fuel costs even with stable gas prices. The degree to which CTs will have to run to serve load is, in turn, highly dependent upon both the availability and price of purchased power. Likewise, if gas prices increase, the per-kWh cost of running a CT will increase even if the unit is not called upon to produce any more kWh. If both these events happen, that is, higher gas prices and the need for higher capacity factors from the Company's CTs (because of either the availability or price of purchased power), customers get hit with a "double-whammy." If purchased power prices increase and gas prices don't, or at least not as much, the spark spread increases, meaning the greater ability of the more efficient combined-cycle unit to compete for off-system sales margins increases relative to the CT-based alternative.

Q. DID STAFF WITNESS SALGO PRESENT WHAT YOU HAVE DESCRIBED AS A REVENUE REQUIREMENTS ANALYSIS?

A. Mr. Salgo discusses an analysis based on one of the resource expansion scenarios discussed above, specifically Alternative 4. The results are shown on his Exhibit HS-2. (Salgo Testimony at 2-3.) Although the analysis itself shows a net benefit to customers from the rate-base option, he dismisses the results by postulating that better heat rates might be obtained in 2007-vintage equipment, thus potentially offsetting all of the benefit.

Q. DO YOU AGREE WITH MR. SALGO'S ANALYSIS?

A. No, although Staff's own analysis would seem to indicate that with an extremely miniscule disallowance from the Company's requested rate-base value for the PWEC units (some $5-6 million), they would be clearly economic from Staff's perspective irrespective of what assumptions are made about the efficiencies of future generation. Moreover, Mr. Salgo himself admits his was only a cursory "spreadsheet" calculation (Salgo Testimony at 23-24) rather than a complete analysis of the type I have conducted and presented in this Docket.

In any event, Mr. Salgo has miscalculated the 2004 impact of his two scenarios (rate-base versus no rate-base). He apparently assumed that the annual impact of fuel and purchased power costs from the APS/PWEC Track B contract in the "no PWEC assets in rate-base" scenario was evenly spread between the first and second halves of 2004 and consisted only of demand costs. However, the Company's work papers indicate that most of these higher costs are in the second half of the year, which contains three of the four months covered by the APS/PWEC Track B contract, and also includes variable O&M payable under the contract. This additional cost (of not rate-basing the PWEC assets) needs to be added to the benefits of the rate-base option, thus putting that option back into the black, this is, producing net customer benefits, even allowing for Mr. Salgo's optimism about the heat rates of future gas generation.

On that last point, Mr. Salgo may or may not be correct that by 2007, turbine manufacturers will be designing and maybe even constructing more efficient machines. However, to get a new power plant in service by 2007, a turbine order would have to be placed much earlier than 2007. Thus, one cannot count on gaining material efficiency benefits from delaying the acquisition of new generation. In addition, Mr. Salgo has assumed that turbine manufacturers will not seek higher prices for more efficient equipment. The industry's recent experience with the introduction of the more efficient LM6000 CTs to compete with the earlier EA or 7FA models would not support such an assumption.

Finally, Mr. Salgo's additional assumption that new construction can be so easily sited and constructed as a single large batch at only a 10% increase in cost over units built in 2001-2002 (Salgo Testimony, Schedule HS-2, ft. nt. 2) is fundamentally unrealistic. To replace the PWEC assets Staff so readily dismisses plus intervening growth would require some 2500 MW of new generation to serve APS customers by 2007. Such a large and concentrated construction program exceeds by a large measure anything the Company has previously undertaken, both financially and from the standpoint of physical resources, even as compared to the Palo Verde construction era of the 1980s. Siting alone would be a significant challenge because most of the best sites were taken during the merchant build-out of the past two or three years. Mr. Salgo also does not consider whether additional transmission infrastructure would be required to accommodate this amount of incremental generation. For these reasons alone, his suggestion that a simple "rule of thumb" RCN figure should somehow be used to measure future construction prudence (Salgo Testimony at 14) is unsupported and unreasonable. To my knowledge, no such simplistic standard of construction prudence has been used anywhere in the United States.

Mr. Salgo's alternative to rate-basing the PWEC assets is a fundamentally unexecutable plan, with the hypothesized new construction necessarily replaced by one or more PPAs. Based on the offers received by APS for such PPAs, the rate-base option is clearly more economic.

Q. ARE THERE OTHER PROBLEMS WITH MR. SALGO'S ANALYSIS?

A. Yes. He did not use either the Staff's recommended cost of capital or depreciation rate in making the comparison of the rate-base option with Alternative 4.

Q. MR. SALGO ALSO HAS INDICATED THAT APS SHOULD HAVE A "DUE DILIGENCE" EXAMINATION OF THE PWEC ASSETS PRIOR TO ACQUIRING THEM (SALGO TESTIMONY AT 26). IS SUCH A "DUE DILIGENCE" REVIEW NECESSARY?

A. No. These are essentially APS-constructed plants to begin with and APS continues to operate the West Phoenix and Saguaro units owned by PWEC. Redhawk is, for the most part, operated by former APS people and since it is under contract to APS for the months of the year it operates the most, APS is quite familiar with its operating characteristics. Moreover, both Redhawk and West Phoenix have long-term maintenance agreements with General Electric and Seimens-Westinghouse that provide APS with complete assurance that the units will be maintained in a manner that will assure their availability for meeting the Company's needs.

Q. YOU DISCUSSED THE COST OF EARLY TERMINATION OF THE APS/PWEC TRACK B CONTRACT AS FACTORING INTO YOUR MARKET VALUE ANALYSIS. IS THE VALUE OF THAT CONTRACT ACTUALLY $219 MILLION AS CLAIMED BY MR. SALGO (SALGO TESTIMONY AT 14) AND STAFF WITNESS JARESS (JARESS TESTIMONY AT 2)?

A. No, although I understand how Staff may have come to such a conclusion. The real issues here are the likely and potential cost to APS customers both during the non-Track B contract months of 2005 and 2006 and after September 2006 if the PWEC units are not rate-based. Without the PWEC units in rate-base, APS is short of high-efficiency (7000 BTU heat rate) capacity during the non-Track B contract months. If the modeling assumption is that the wholesale market is sufficiently robust to displace all of the Company's less-efficient generation with economy energy during those months, the difference in fuel and purchased power costs between the "PWEC assets in rate-base" case and the APS/PWEC Track B contract case is minimized thus making it appear that the Track B contract captures most of the short-term benefit of the PWEC assets. In any event, my earlier discussion of the energy price risks from increased dependence upon less efficient capacity is also relevant here. In other words, how much value one assigns to having the PWEC assets available year-round during 2005 and 2006, which is only the case if they are rate-based, depends on how much that increased dependence is expected to cost during those eight non-Track B months. That, in turn, is directly correlated to natural gas and purchased power costs. For example, if gas and purchased power costs were to return to 2000-2001 levels, the higher cost to APS customers for these non-Track B months would be staggering. Thus, in some respects, one could view any foregone benefit from the APS/PWEC Track B contract to be a form of option premium for the right to have the PWEC assets at cost for the 28 years of assumed useful life after the Track B contract expires and a hedge against unexpected movements in the natural gas and power markets during the non-Track B months of 2005 and 2006.

Q. **ARE THERE OTHER MEASURES OF THE APS/PWEC TRACK B CONTRACT'S VALUE TO APS CUSTOMERS?**

A. Yes. In fact, I believe a better way of valuing the APS/PWEC Track B contract is to compare it with the cost of replacing it with standard market products at the forward curves or daily call options used to evaluate the contract on April 23, 2003. These still show that the APS/PWEC Track B contract has value compared to market, but that value is a small fraction of $219 million for the 2005 and 2006 contract periods.

Q. **SHOULD THE COMMISSION SUBTRACT $99 MILLION FROM THE ANNUAL REVENUE REQUIREMENT ATTRIBUTABLE TO RATE-BASING THE PWEC ASSET IN ORDER TO GIVE APS CUSTOMERS THE SUPPOSED BENEFITS OF THE APS/PWEC TRACK B CONTRACT AS RECOMMENDED BY MR. SALGO (SALGO TESTIMONY AT 25)?**

A. No. The $99 million "credit" is premised on the $219 million number, which is again based on an unreasonable assumption concerning economy energy availability and price and does not capture the increased gas and power price risk associated with the non-Track B months of 2005 and 2006. It also ignores the fact that in my resource alternatives, the "value" of the APS/PWEC Track B contract is already factored into the revenue requirements analyses. If we now subtract out that Track B contract impact from the rate-base revenue requirements, you have counted it twice.

Even under the best of the resource alternatives that include the APS/PWEC Track B contract, Alternative 4, the present value revenue requirements difference between that alternative, which gives APS customers 100% of any benefits from the APS/PWEC Track B contract in 2005 and 2006, and the rate-base proposal is no higher than $32 million. To reduce that difference to zero, which gives customers the benefits of both the Track B contract and the unreasonably optimistic assumptions about executing the balance of Alternative 4, would require a reduction in the rate-base value of the PWEC units by approximately $20 million. A reduction in rate-base value of $20 million translates into far less than a $20 million annual revenue requirements "credit," let alone a $99 million "credit."

D. 2003-2004 Company RFP

Q. PLEASE DESCRIBE THE RFP PRESENTLY BEING CONDUCTED BY APS.

A. On December 3, 2003, APS issued an RFP seeking long-term supply resources, either through the acquisition of a power plant or plants, or through a PPA of at least 20 years duration. The RFP sought an unspecified amount of capacity in increments of between 35 MW and 550 MW. Because of the existence of the Track B contracts with PWEC and others, the Company seeks to delay the financial impact of the acquisition until 2007, when the capacity could be fully needed, although APS is willing to accept delivery by year-end 2004 if the seller will repurchase the output from the plant until 2007. Any transaction is subject to appropriate approvals by this Commission and FERC.

A bidders' conference was held in Phoenix on December 15, 2003. Some nine parties, who had previously sent APS notice of their interest in participating, sent representatives to the conference. On these, all nine actually sent in bids by January 21, 2004. The complete list of bidders is attached to Mr. Wheeler's Rebuttal Testimony as a confidential schedule.

As also noted in Mr. Wheeler's Rebuttal Testimony, APS wished to avoid discussing the RFP results in this rate case both to better preserve the confidentiality of those bids that do not eventually result in an agreement with the Company and to protect our ability to negotiate with the short-list parties. Unfortunately, others (including but not limited to the ACPA) directly raised the RFP and the need to market test the PWEC assets in some manner in their direct testimony and in earlier pleadings filed in this proceeding. Accordingly, APS must respond to these accusations. However, APS will limit access to any bidder-specific information to the Commission and its Staff unless ordered otherwise by the Commission. Second, the data actually used in my testimony will neither identify any specific bidder nor reveal any specific pricing terms, and even then, will (if appropriate) be provided only under seal and on a confidential basis.

Q. HAS APS COMPLETED ITS INITIAL ANALYSIS OF THE BIDS RECEIVED IN CONJUNCTION WITH THIS RFP?

A. The economic analysis of the responsive bids was undertaken to determine the "short list" parties in the early part of February, 2004. The responsive bids originally received included PPAs and asset-sale proposals. From that initial group, at least two proposals did not meet minimum threshold criteria, and another bidder withdrew its asset sale proposal. The Company is now completing its "due diligence" review of the plants APS is considering purchasing or that the seller is using to back its PPA proposal. A thorough final financial analysis will also be conducted prior to any actual selection of a bid or bids and the finalization of an agreement.

Q. HOW WAS THE ECONOMIC ANALYSIS CONDUCTED TO GET TO THE SHORT-LIST?

A. For responsive bids, we calculated the 30-year levelized busbar cost in dollars per megawatt hour. The levelized busbar cost calculation captures the present value of the revenue requirements of each alternative under cost-of-service regulation. For PPA offers of less than thirty years, we filled in the balance of the period in a fair and consistent basis with what we believed was the least cost supply option at the time.

Q. WHAT DO THE BIDS REVEAL?

A. The summary of results is shown on the first page of Schedule AB-6RB. Again, even in this confidential summary material and in any economic analyses, APS has attempted to fully preserve the confidentiality of individual bidders' data, which is why no names or pricing terms have been attached to a specific bid. What I can say in this public forum is that the levelized cost of the legitimate proposals ranged from \$80 MWh to \$90 MWh. This, as can be seen in Schedule AB-6RB, is significantly above the levelized cost of Redhawk 1 and 2, as well as West Phoenix CC-5. Levelizing a stream of future revenue requirements achieves the same goal as using cumulative present value revenue requirements, but it produces numbers that are arguably easier to understand and compare on an annual basis. I have excluded from that range, and from the results displayed and analyzed in

Schedule AB-6RB, proposals involving CTs. CTs have very high costs per MWh because they operate at much lower capacity factors. They are not really comparable to any of the PWEC combined-cycle units.

Even without using the specific numbers in this public forum, I can state the following conclusions:

a. The PPAs offered were uniformly more costly to customers than the PWEC rate-base proposal, even before consideration of the cost of any credit support APS may prudently be required to obtain in support of such PPAs.

b. The binding asset sales finally offered were not comparable either in size or type of unit with the PWEC assets and were, in any event, more costly than rate-basing the PWEC units.

c. The "real world" PPA pricing, as evidenced by the RFP bids received, was highly correlated with our existing GE MAPS modeling of prices under the "cyclical" scenario, which gives me even greater confidence that the analyses we provided during discovery showing the benefits of our rate-base proposal and the soundness of our planning process were accurate.

Q. AS YOU PREVIOUSLY INDICATED, COULD THE PPA BIDS ALSO BE USED AS A PROXY FOR LONG-TERM MARKET PRICES IN YOUR DCF AND REVENUE REQUIREMENTS ANALYSES OF THE VALUE OF THE PWEC ASSETS?

A. Yes.

Q. HOW DID YOU USE THE RFP RESULTS TO CALCULATE FUTURE MARKET REVENUES FROM THE PWEC UNITS IN YOUR DCF STUDY OF "MARKET VALUE"?

A. In addition to the three market scenarios modeled through GE MAPS, I took a look at what could be the expected market revenues from the PWEC assets based on the results of our RFP. The first alternative took the best four PPA offers. The second two of what I call, the "PPA alternatives" involves different combinations of three of the PPA offers, including the best PPA offer. It was necessary to use multiple offers because no one of the PPA offers would have encompassed the same amount of capacity as the four PWEC combined-cycle units. I also fashioned a hypothetical "representative" PPA that was just slightly less costly than the lowest bid received in that RFP. The "representative" PPA used the long range marginal cost ("LRMC") of a combined-cycle unit completed in 2007 and was for a comparable amount of capacity as the four PWEC combined-cycle units, even though no such proposal had actually been made to APS in this RFP. For those PPA offers less than the 30-year life assumed for the PWEC units, I used the "fundamental" market's simulated prices for the years after 2027. To bring the DCF analysis of these scenarios back to the 1/1/05 date used for valuing the PWEC assets, these "fundamental" market prices were used for the non- Track B months of 2005 and 2006, with the APS/PWEC Track B contract used for the remainder of 2005 and 2006, thus fully capturing whatever benefits to customers derive from that contract.

Q. HOW DID YOU THEN EVALUATE SAGUARO CT-3 USING A PPA ALTERNATIVE MARKET PRICE?

A. Because none of the PPA offers were for CT units similar to Saguaro CT-3, I substituted "fundamental" market prices for the entire 30-year evaluation period.

Q. WHY WOULD IT BE REASONABLE TO EVALUATE THE MARKET VALUE OF THE PWEC ASSETS USING POTENTIAL PPA AGREEMENTS FOR DETERMINING FUTURE MARKET PRICES?

A. The use of the "PPA alternatives" as proxies for market prices was based on the reasonable assumption that PWEC would not expect to do materially worse in a long-term market PPA than did any of the non-affiliates that submitted competitive bids in the Company's RFP.

Q. WHAT DID THESE DCF RESULTS SHOW?

A. The DCF value of the PWEC assets, using the various PPA pricing schemes discussed above, was between $87 million (using APS' cost of capital) and $647 (using Staff's cost of capital) million greater than their cost. See Schedule AB-7RB.

Q. HOW DID YOU ALSO INCORPORATE THE RFP RESULTS INTO THE REVENUE REQUIREMENTS OR REPLACEMENT COST STUDY DISCUSSED EARLIER IN YOUR REBUTTAL TESTIMONY?

A. I formulated six alternative resource plans in which I substituted, respectively, the highest PPA offer that met the Company's preliminary screening criteria, the lowest PPA offer meeting such criteria, and the average of all the PPA offers meeting those same criteria. Since neither the highest nor lowest PPA offer was for as much capacity as the PWEC combined-cycle units, some blend of PPA offers would likely have had to be used as a realistic "replacement cost," but I believe the analysis I did will make the point that the PPA offers were uniformly less economic than rate-basing the PWEC assets.

Q. PLEASE CONTINUE.

A. I substituted these three values into two scenarios, one in which I replaced all of the PWEC combined-cycle units with PPAs and a second in which only West Phoenix CC-4 and West Phoenix CC-5 were so replaced, with Redhawk then replaced with CTs. In all other respects, assumptions used for the revenue requirements comparisons were identical to those used for the other 12 scenarios discussed previously in the "replacement cost" portion of my Rebuttal Testimony.

Q. WHAT DID THE REVENUE REQUIREMENTS ANALYSIS OF THE RFP RESULTS SHOW?

A. The customer benefit from the rate-base option ranged from between nearly $312 million and nearly $893 million. See Schedule AB-8RB.

Q. DON'T YOU HAVE TO MAKE NUMEROUS ASSUMPTIONS IN A THIRTY-YEAR ANALYSIS ABOUT FUTURE FUEL PRICES, O&M, PURCHASED POWER, ETC.?

A. Yes, but we made the same assumptions for each of the options reviewed as well as for the PWEC units. Thus, any future deviation of say, actual gas prices, from the level modeled in the economic analysis, would obviously change the total present value of each alternative but not their ranking and would have very little impact on the relative differences between alternatives.

Q. WHAT ELSE HAVE YOU CONCLUDED FROM THE RFP RESULTS?

A. Just as was the case during the Track B proceeding, there are not a lot of bargains out there waiting to serve APS customers. The merchant generators apparently see what Chairman Marc Spitzer termed the "inevitable" upturn in tomorrow's market (Letter of Chairman Marc Spitzer dated February 19, 2004), an upturn which APS has modeled into its planning analyses for several years now, and are not willing to "give away" their plants today or to make long-term commitments of those plants in the form of PPAs that are priced below market fundamentals. This was also what we saw after our 1995 RFP, which is discussed in my Direct Testimony and which eventually led to our decision to construct the PWEC Arizona assets.

Q. EVEN IF THERE WERE DISTRESSED ASSETS FOR SALE TO APS, WOULD YOU FACTOR THAT INTO YOUR LONG-TERM RESOURCE PLANNING PROCESS?

A. I would certainly adjust our future need for resources should such a "distressed" asset become available to APS and its acquisition by the Company thereafter negotiated and approved by the appropriate regulatory agencies. By "distressed," I mean an asset whose owner is under financial or other pressure to sell the asset and thus is likely willing to accept less than we believe to be fair market value. Although no such assets are available to APS during the present RFP, such may from time to time come on the market. However, these assets represent opportunities to be taken advantage of – they are not a "plan" that can be either executed or relied upon to serve our customers reliably over the long haul.

E. Reproduction Cost

Q. DID YOU CONDUCT AN ANALYSIS OF WHAT IT WOULD COST TO REPRODUCE (RCN) THE PWEC ASSETS TODAY?

A. Yes. I have performed a similar RCN calculation of PWEC generation as is in Mr. Wheeler's Direct Testimony and also mentioned in my Direct Testimony at page 4.

Q. PLEASE DISCUSS THE ASSUMPTIONS AND RESULTS OF YOUR RCN STUDIES?

A. I used the RCN calculation from Schedule B-3 of the Company's June 2003 rate application. Then I trended that RCN up to January 1, 2005 using a conservative annual inflation rate of 1.5%. I then replaced the two Redhawk units, West Phoenix CC-4, West Phoenix CC-5 and Saguaro CT-3 with four brand new combined-cycle units and one new simple cycle unit of equal size and efficiency as of 1/1/05 and at the trended value I described above. The operation (e.g. energy production from the dispatch model) for these units was unaltered from the original PWEC units' dispatch model. I also assumed the O&M cost was not increased or decreased for the newer units as compared to the PWEC units. The annual capitalized fixed charge calculation assumed the same capital structure as is in APS' rate filing (i.e., 55% debt and 45% equity). The cost of equity in the base case was that requested by APS in this proceeding. I performed a sensitivity analysis on the cost of debt. These assumptions along with results of these RCN studies are presented in Schedule AB-9RB. The results clearly show a range of $495 million to $587 million in increased cost to our customers compared to the case in which the existing units were proposed to be rate-based at book value. The present value benefit to rate-basing is between $196 million and $248 million. This means that if RCN is considered to measure the "market value" or "prospective value" of the PWEC assets, that value is significantly greater than their cost.

V. REBUTTAL TO RUCO WITNESS SCHLISSEL

Q. HAVE YOU REVIEWED MR. SCHLISSEL TESTIMONY STARTING AT PAGE 8 THAT RELATES TO HIS COMPARISON OF ANNUAL REVENUE REQUIREMENTS RESULTING FROM RATEBASING THE PWEC UNITS AND THE TOTAL MARKET REVENUES ASSOCIATED WITH THOSE UNITS?

A. Yes I have.

Q. WILL YOU PLEASE COMMENT ON THAT ANALYSIS?

A. I will characterize Mr. Schlissel's analysis as a "crossover analysis." By that I mean he attempts to define the point in time when a generating unit's annual regulated costs (revenue requirements) and cumulative regulated costs become less than annual market revenues and cumulative market revenues (or putting it a different way, annual and cumulative cost savings to customers from not having to secure that amount of power from the market) in both nominal (undiscounted) and present value (discounted to reflect the time value of money) terms. His analysis determines future market revenues in much the same manner as I did in arriving at the market value of the PWEC assets in my DCF study. However he concentrates on the period it may take for cumulative market revenues to exceed regulated costs (that is, when the PWEC assets produce net benefit to our customers) rather than the present value of the total net benefit itself. This is not what a utility resource planner would do for reasons I discuss later in my Rebuttal Testimony.

The first observation I must make about Mr. Schlissel's analysis is that he chose, without explanation, for his market price case only one, and in fact the lowest, of the three potential market scenarios provided to him through the discovery process, which I previously have described as the "fundamental" market scenario. Had he used what I believe (and the RFP results support) to be the more likely "cyclical" market scenario, the crossover points would occur several years sooner. The same is true had he used the PPA bids from the RFP as a measure of the long-term market revenues reasonably expected to be produced by the PWEC assets. I have reproduced Mr. Schlissel's crossover analysis in my Schedule AB-10RB and have marked the crossover points under each market price scenario for easy reference.

The second point I want to make is that while Mr. Schlissel states that he believes it would be most appropriate to use the fundamental LRMC method to measure crossover points (Schlissel Testimony at 15), he in fact used market capacity prices for 2004 and 2005 that do not reflect this method and which are far below the LRMC values for those years. In addition, in the calculation of the market revenues to be derived from the PWEC assets for the period July 1 through December 31, Mr. Schlissel simply takes the 2004 full-year capacity price and divides it by two. This implies that capacity in the Desert Southwest has the same market value during each month of the year, which flies in the face of both available market data and common sense. A more accurate analysis of the capacity value relationship for the second half of any calendar year would assign approximately 70% of the annual amount because the capacity value of generating assets is higher in summer months compared to other months and the second half of the year contains more and hotter summer months than the first half (July, August and September versus May and June). The resulting values from correcting capacity prices for 2004 and 2005 and the underlying cost of capital are shown on page 2 of Schedule AB-10RB. As you can see, the crossover point takes place many years sooner than shown in Mr. Schlissel's original analysis.

Q. DO YOU HAVE ANY OTHER CRITICISMS OF MR. SCHLISSEL'S CROSSOVER ANALYSIS?

A. Yes. Mr. Schlissel prepared his analysis using the capital structure and capital cost rates provided by the Company during discovery. These included a 55% debt and

45% equity capital structure with an assumed cost of debt of 7% and an equity cost rate of 11.50%. As I have discussed earlier, these assumptions have some value in making comparisons to earlier DCF and busbar analyses conducted by the Company but are higher that <u>any</u> of the cost of capital recommendations in this proceeding. These capital cost assumptions do not impact the market revenues derived from the units but do impact the regulatory revenue requirement case. If Mr. Schlissel had used the Company's actual embedded cost of debt rate of 5.76%, which is what is being requested in this proceeding, rather than the 7% rate, the crossover points would have occurred an additional year sooner. However, far more dramatic is the impact of RUCO's own cost of equity recommendation on Mr. Schlissel's calculations. If Mr. Schlissel had used RUCO's recommendation of capital cost rates, the crossover analysis would show net benefits to customers <u>in the first year the PWEC assets were included in rates</u>. This is shown on both pages 1 and 2 of Schedule AB-10RB.

Q. WHAT DOES MR. SCHLISSEL'S CROSSOVER ANALYSIS TELL YOU ABOUT THE "MARKET VALUE" OF THE PWEC ASSETS?

A. Even using Mr. Schlissel's market prices and higher (than any of the cost of capital recommendations) incremental capital cost structure discussed above, the DCF calculation produces a value of $1.058 billion compared to the $895 million rate-base cost of the PWEC assets at July 1, 2004, or some $163 million above book value. With the various corrections and alternative market price scenarios I have discussed above, DCF "market value" increases to as high as $1.670 billion. I provide the indicated DCF "market value" calculations at page 3 of my Schedule AB-10RB. In all of these instances, I have carried out Mr. Schlissel's analysis for the remaining ten years of the PWEC assets' book life.

Q. DO YOU HAVE A MORE FUNDAMENTAL OBJECTION TO MR. SCHLISSEL'S FOCUS ON "CROSS-OVER" POINTS?

A. Yes. Just as Staff witnesses Salgo and Jaress cannot seem to get beyond what they believe are the benefits of the APS/PWEC Track B contract, even in the face of the much greater benefits received by our customers in the 28 plus years the PWEC assets would be serving our customers after Track B, and despite Staff witness Smith's admonition about life-cycle economic analysis being what is important, Mr. Schlissel's study and eventual recommendation focuses on short-term rate implications rather than life-cycle benefits. No utility resource planner would sacrifice significant present value benefits for short run cost savings and neither should regulators fail to seize this opportunity to secure for APS customers what even Mr. Schlissel's and Mr. Salgo's analyses, not to mention my own, show are overall net benefits just because of the impact such a decision would have in this single rate case. In fact, as can be seen by the results of my replacement cost or revenue requirements study, all the alternative supply expansion scenarios would have worse economics for customers and would either have a "cross-over" point yet further into the future or would never have a "cross-over" point.

Perhaps an analogy would help here. Few of us have ever had to evaluate the relative economics of electric power supply options, but virtually every adult has bought a car. If one's only concern were the monthly payment out-the-door for a particular model of car, it is almost always the case that leasing the vehicle appears cheaper than buying it. Of course, after three years of making payments on the car you purchase, you still have a three year old car. In the leasing scenario, you have nothing. So unless you plan on walking a lot, you have to obtain new transportation at the end of the lease term. And if I again use the same short-run out-of-pocket cost per month analysis, I will choose to lease a second vehicle, and the cycle begins again. On the other hand, if you look out, say, twenty years to determine whether, in the long run and on a present value basis, it is better to buy or lease, you may well find that buying your car is the better economic choice. And even this simplified economic analysis ignores the not easily quantified benefits of ownership, because just as your typical car lease imposes mileage limitations and may require the vehicle to be serviced in a specific way and at a specific place, no PPA can be drafted that gives the buyer as much operating flexibility as outright ownership of the generation, even aside from the issues of credit, default and contract performance inherent in any long-term PPA.

VI. REBUTTAL TO ACPA WITNESS KALT

Q. HAVE YOU REVIEWED ACPA WITNESS KALT'S EXHIBIT JPK-10 REGARDING VERTICAL INTEGRATION?

A. Yes. First of all, I need to correct several things about the Exhibit. First, it has double-counted PWEC generation in the APS/PWEC column. Second, he has included both Cholla 4 (380 MW), which is owned by PacifiCorp but operated by APS, and an Imperial Irrigation District unit in Yuma (75 MW) as APS generation. Third, he has ignored reserve requirements in calculating peak load needs for each of the utilities shown. I provide corrected exhibits in Schedule AB-11RB. It shows APS, with or without PWEC, to be much more middle-of-the-pack.

Q. WHAT ELSE HAVE YOU OBSERVED ABOUT THIS EXHIBIT?

A. An obvious consequence of not being more vertically-integrated is to be more exposed to the market. Note that the utilities shown to be most exposed to the market are the three major California utilities and Nevada Power Company. With one of those entities bankrupted and two more either having barely escaped bankruptcy or still facing bankruptcy, this is hardly a ringing endorsement of depending on the market. And, your customers will also be forced to pay higher prices.

Don't get me wrong. APS has relied and is relying on the market, and the market has supplied, at a price, the Company with power during critical periods, But APS has managed that level of exposure through its resource plans. Because of the asset-backed resource plan announced in 1999, with its planned and managed levels of APS market exposure, the Company was able to avoid being pressured into signing expensive market contracts. This use of the PWEC assets as, in effect, a market hedge is also discussed in Mr. Davis' Rebuttal Testimony, and it allowed APS to decrease rates at the same time others were increasing rates substantially. I show the rate impact of excessive market exposure in my Schedule AB-12RB.

Q. HOW AND WHY DID THESE FOUR UTILITIES GET IN SUCH A PREDICAMENT?

A. The interesting thing is that it happened so fast. As can be seen in Schedule AB-13RB, my analysis for 1998 indicated levels of market exposure for those four entities was similar to that of APS. While APS chose to have PWEC build assets to support its needs, these other entities chose to rely on the market, and in several cases actually divested portions of their owned generation assets to non-affiliates. These same utilities are now exploring avenues for increasing owned generation to hedge their levels of market exposure with their regulatory commission's support.

It should be noted that APS' exposure to the market, without the PWEC units, would be at the same 30% level in 2003 as led to the downfall of the California and Nevada utilities and their customers. In the case of APS, that exposure increases each year by 4% or more. And once you fall behind in meeting Arizona's growth, it will be difficult and more expensive to catch up.

Q. EVEN IF APS WERE BELIEVED TO BE OVER-EXPOSED TO THE MARKET, COULD NOT IT BEGIN NEW CONSTRUCTION TO ADDRESS THAT EXPOSURE?

A. Yes, but any new construction could take time, and it takes far less time for that market exposure to do very serious damage to both the Company and its customers. In my Schedule AB-14RB, I show the impact of a single year's (2001) over-dependence on the market. Pacific Gas & Electric and Southern California Edison, two California utilities cited by Mr. Kalt as examples of less integrated than APS, lost nearly $5.5 billion. San Diego Gas & Electric, although believed to be more hedged than its California counterparts going into the California energy crisis, still lost over $800 million. Nevada Power, a smaller utility than APS, ran up a billion dollar tab, much of which was eventually disallowed by its state regulators, thus aggravating that utility's ongoing financial distress. In contrast, APS' increased costs were roughly $120 million – not an insignificant number but a far cry from the experiences of these others and a figure that did not prevent the Company from actually reducing rates in 2001, not to mention the five annual decreases prior to 2001 and the two additional decreases since 2001.

VII. <u>RESPONSE TO COMMISSIONER GLEASON LETTER DATED DECEMBER 16, 2003</u>

Q. HAVE YOU READ COMMISSIONER GLEASON'S LETTER DATED DECEMBER 16, 2003, WHICH HE FILED IN THIS DOCKET?

A. Yes, and I am pleased to respond. Although I will slightly paraphrase some of these questions, I believe my responses will be helpful in the Commission's consideration of this matter.

A. Gleason Question No. 1

Q. HOW DOES APS DEFINE "BASELOAD"? IS THIS A STANDARD DEFINITION USED THROUGHOUT THE INDUSTRY? IF NOT, WHY NOT?

A. APS characterizes its generating assets duty cycle in a manner similar to the electric industry as a whole. As a general proposition, those generating units operating at or above a 50% capacity factor in APS' portfolio of generation assets would be viewed as a base-load duty cycle generation. This type of generating unit will be operated day-in and day-out to provide electricity to our customers or selling into other neighboring electric markets. In planning terms, the anticipated capacity factor of the generating unit would be estimated over its lifecycle operation. However, there are many nuances associated with any characterization of a generating unit's duty cycle in actual operation, which nuances I will address below.

The Electric Power Research Institute ("EPRI"), which is the electric industry's technical issues body, has widely publicized a definition of power plant duty cycle ranges, which is as follows:

i. base-load power plants are those which fall within 50-85% capacity factor range;

ii. intermediate duty cycle plants are those running above a 20% capacity factor up to the 50% level;and

iii. peaking duty cycle would encompass those resources that are expected to run at less than 20% lifetime capacity factors.

As to the nuances I mentioned above, let me emphasize that although the power plant capacity factor is the key driver to characterizing a power plant's duty cycle, there are other significant factors that affect power plant duty cycle. For example, one must consider the control equipment installed on a power plant, which allows the unit to start up and shut down safely, as well as the unit's ability to ramp up and down to follow load. If such load following, and the resultant stress and strain on the equipment, can be done without degrading the plant's life expectancy, it is more likely that the unit will be adapted to an intermediate duty cycle. Also, initial construction costs, fuel availability, fuel type and source, fuel price, power plant efficiency, plant/unit size and design, and technological obsolescence can contribute to whether a power plant initially designed as base-load would continue to operate or change its duty cycle characterization. After all, all of our originally oil-fired steam turbine plants such as those at Ocotillo and Saguaro, when first built, operated as base-load. As the price of petroleum skyrocketed in the late sixties and seventies, the Company turned to coal and nuclear generation. Eventually these older units, now converted to gas, became first intermediate and then peaking units. However, when the market blew up in 2000 and 2001, these same units returned to an intermediate duty cycle for that same period.

I have attached as Schedule AB–15RB a listing of each of the APS-owned generating assets and their intended classification of duty cycle as we see them today. I would like to point out that of the generation assets shown on this Schedule, only the simple cycle CTs were originally installed with the intent of being peaking duty cycle; all other generation units were originally intended to be base-load duty cycle.

B. Gleason Question No. 2

Q. IN MEGAWATTS, WHAT WAS THE COMPANY'S ACTUAL BASELOAD IN 2000, 2001, 2002, AND 2003? PLEASE EXPLAIN YOUR ANSWER IN DETAIL AND PROVIDE A LOAD DURATION CURVE FOR THE SAME YEARS.

A. Let me begin by providing a brief explanation of what a load duration curve is and what it shows to a system planner and operator. Our customers use the highest quantities of electricity during summer and least amount during the spring and fall. Historically, this customer electricity use pattern, when measured on an hourly basis, shows the highest hourly demand occurring around 4 PM or 5 PM during a summer day. The lowest customer hourly demand would normally occur during a spring or fall day sometime past midnight. For each hour of the year, the level of demand on the APS system is measured and this information stored electronically. The Company also estimates projected years' load duration for budgeting and planning purposes based on APS customers' projected monthly energy use, projected peak load, and historic electricity use patterns within the days of each month. The results are then plotted starting with the hour of highest demand (peak load) through the last hour which has the lowest demand (minimum load). It is a curve that shows the hours of the year on the x-axis and the level of demand on the y-axis.

APS system specific plots for the years 2000, 2001, 2002 and 2003 are shown in my Schedule AB-16RB. The total capacity, in megawatts, for those plants operated as baseload for each year is also shown, as requested. In this Schedule, I also provide both the monthly and annual capacity factor achieved by each APS-owned power plant during these four years. And finally, in Schedule AB-16RB, I show the APS power plants "stacked" in order of their incremental costs on the load duration curve provided in Commissioner Gleason's Exhibit-G2, which was based on an example provided by Mr. Davis in Docket No. E-01345-02-0707.

I have also provided similar data on the PWEC units sought to be acquired by APS in this proceeding. West Phoenix CC-4 (114 MW) was operated in part of 2001, all of 2002 and the first half of 2003 to serve APS loads prior to the effective date of the Track-B contracts. Similarly, Redhawk Units 1 and 2 (1000 MW) also primarily operated serving APS loads in the latter half of 2002 and the first half of 2003. With the beginning of the Track B contracts, each of these units, along with West Phoenix CC-5, serve APS customers during the Track B months of June through September. These assets would be on the border between intermediate and base-load duty cycles using the definition I gave earlier.

C. Gleason Question No. 3

Q. PLEASE PROVIDE THE COMPANY'S FORECAST OF APS BASELOAD FOR THE YEARS 2000-2003 AND INDICATE WHEN SUCH FORECAST WAS MADE.

A. The projection of the capacity factor for our plants is an ongoing process at APS. We project capacity factor (e.g. base-load/ intermediate/peaking duty cycle) for our power plants annually and sometimes twice a year. These projections are provided in Schedule AB-17RB. Our projections did not anticipate the California energy crises would be nearly as severe as it actually turned out to be.

This question really begins getting to the heart of the resource planner's job. As I stated in my Direct Testimony (Bhatti Direct Testimony at 25), APS' resource plans are built around incremental additions to our existing and proven portfolio of base-load generation resources. Also, on page 46 of my Direct Testimony, I show how APS' projection of its need for new resources was changing over time. Thus, for each LRF and resultant resource plan, we take the projected peak loads and derive hourly demands. This gives us the data to plot the load duration curves as well as an indication of the type of new resources we will need to acquire to economically and reliably meet such future loads. The source for the projected data provided in Schedule AB-17RB is the Company's budget forecast prepared in December 1999 and subsequent budget forecast prepared in December 2000.

D. Gleason Question Nos. 4, 5 and 6

Q. WHAT DOES APS FORECAST ITS BASELOAD WILL BE FOR THE YEARS 2004 THROUGH 2010? PLEASE EXPLAIN YOUR CALCULATION AND PROVIDE PROJECTED LOAD DURATION CURVES FOR EACH SUCH YEAR.

FOR YEARS 2004 – 2010, WHICH APS GENERATING UNITS WILL APS HAVE TO OPERATE IN ORDER TO MEET ITS BASELOAD OBLIGATIONS, ASSUMING NONE OF THE PWEC UNITS ARE INCLUDED IN APS' RATE-BASE? HOW MUCH ADDITIONAL ENERGY AND DEMAND WILL APS HAVE TO PURCHASE IN EACH YEAR TO

MEET ITS BASELOAD OBLIGATIONS? ITS TOTAL OBLIGATIONS? PLEASE PROVIDE THIS INFORMATION BROKEN DOWN BY MONTH.

FOR YEARS 2004 – 2010, WHICH APS GENERATING UNITS WILL APS HAVE TO OPERATE IN ORDER TO MEET ITS BASELOAD NEEDS, ASSUMING ALL PWEC UNITS ARE INCLUDED IN APS' RATE-BASE? HOW MUCH ADDITIONAL ENERGY AND DEMAND WILL APS HAVE TO PURCHASE IN EACH YEAR TO MEET ITS BASELOAD OBLIGATIONS? ITS TOTAL OBLIGATIONS? WILL APS PRODUCE EXCESS CAPACITY OVER WHAT IS NEEDED TO SERVE ITS NATIVE LOAD? PLEASE PROVIDE THIS INFORMATION BROKEN DOWN BY MONTH.

A. These remaining requests can be explained together as follows.

These questions seek to determine which APS generating units will be used to meet the base-load obligations predicted for each year 2004 through 2010 under two alternative cases. Case 1, the Company's forecast, is where the PWEC assets are part of the resource plan and included in the Company's ratebase, and Case 2 is where the PWEC assets are not part of the resource plan. Under each Case, it is also requested that we provide information on how much additional energy and demand APS has to purchase to meet its base-load obligation and its total obligation on a monthly basis.

In response to these questions, I have performed APS-specific and detailed simulations of our generation system economic dispatch for the period 2004 through 2010 with (Schedule AB-18RB) and without (Schedule AB-19RB) the proposed PWEC-owned generation. I have kept the APS/PWEC Track-B contract during the four summer months unaltered. I have further prepared monthly loads and resource tables again with (Schedule AB-20RB) and without (Schedule AB-21-RB) the PWEC generation for the same period to show the capacity and energy deficit of our customers.

The results are derived from using the Company's most recently available customer load and energy projections (from the 2003 LRF), shaped using APS system representative historic hourly load patterns. Such projections are a normal part of the Company's planning process and are generated by sophisticated computer economic dispatch models such as GE MAPS and RTSIM. The former is generally used in the spring of each year for long-term planning, while the latter model is used in the fall for budgeting and shorter-term financial forecasting purposes.

Case 1, which shows the PWEC assets at APS, indicated that APS coal and nuclear generation will continue to operate as base-load units. The older APS gas/ oil generation however, in this case will operate on a peaking/intermediate duty cycle. The more efficient PWEC units will operate as first intermediate and then base-load duty cycle during this planning horizon. I would note that the PWEC assets were planned for a significantly longer operating life than just through 2010. In Case 2, which was analyzed without the PWEC generation, annual and monthly results, clearly show that all of the existing APS-owned generation has a potential to operate as a base-load generation unless APS relies on the market for very significant amounts of purchased power.

As far as there being any excess power or energy, the Company's assets have historically exercised opportunities to sell excess energy from its power plants to other utilities. This has benefited our customers for decades, and APS expects to continue to produce off-system margins from such sales. The budgeted amount of energy which is assumed to be sold to other utilities is provided in Schedule AB-18RB on page 3 of 7. The amount of deficit energy likewise is provided in Schedule AB-19RB on page 3 of 7.

In Schedules AB-20RB and AB-21RB, I address the "excess capacity" issue. Unfortunately, what we have is a capacity deficit rather than surplus capacity. Indeed, that capacity deficit increases significantly both during summer and winter months if the PWEC assets are not acquired by APS. The Case including the PWEC generation alleviates the winter capacity problem to a large extent, but the Company will still have to build or buy (either outright in the form of a plant or indirectly through purchased power) generation to meet its summer peak load.

Lastly, I would like to add some economic and rate impact analysis to this discussion. Specifically, how much might it cost or save APS customers under these different scenarios? The cost associated with any uneconomic operation of our generation system to meet APS customers' needs would be significant, and the more uneconomic the choice, the more such significance is magnified. Earlier in my Rebuttal Testimony, I note that customers can be exposed to extreme price volatility from higher gas and purchased power costs even if there is enough capacity to meet load, and thus generation expansion scenarios based on CTs present increased price risk from being relatively short on energy. If APS were to rely on the market to meet a large part of both its capacity and energy needs, that risk is magnified. And even if things unfold in the future as predicted by our models and as evidenced by the present RFP results, such dependence comes at the expense of higher costs – in some scenarios very much higher costs – to customers.

VIII. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. Our resource planning process has focused and continues to focus on the needs of customers. It examined viable alternatives and conducted extensive analyses before embarking on the resource plan that resulted in the construction of the PWEC Arizona assets. Even in hindsight, that plan has been shown to be the one most likely to produce the lowest incremental cost to APS customers.

Whether one uses DCF, as suggested by Staff, RUCO and myself, or values the PWEC assets at reproduction cost or replacement cost, their "market value" or "prospective value" to APS customers exceeds the cost APS is asking to be included in rate-base <u>even after consideration of the APS/PWEC Track B contract</u>. Indeed, the recent PPA offers received by the company in response to its RFP are the best evidence of the customer benefit from rate-basing the PWEC assets. Disagreements about the size of customer benefit should not obscure the fact that such benefit exists. Neither should a debate over the timing of those benefits detract from the overwhelming evidence that benefits will come and they will be substantial. And although one might not be expecting another meltdown of the power market like we saw in 2000-2001, as Mr. Davis notes, no one expected to see the first one. Moreover, as we also saw in California and throughout the West, all its takes is one such market blowout to cause spiraling rates and financially-devastated utilities.

Q. DOES THIS CONCLUDE YOUR WRITTEN REBUTTAL TESTIMONY?

A. Yes.

Retrospective Simulation of APS Supply & Demand With Alternative CT Plans

Alternative	Plan Description:	2003-2032 [1] Benefit NPV $Million
Plan A	Redhawk CC 1&2 Built as 50% EA's and 50% LM6000's	311.7
Plan B	Redhawk CC 1&2 Built as LM6000's	402.3
Plan C	Redhawk CC 1&2 Built as 50% EA's and 50% LM6000's W. Phoenix CC 4&5 Built as LM6000's	620.0

Note: (1) Value above rate base cost. Comparison of Base plan 2003 LRF in which PWEC units are rate based vs prospective alternative resource plans with combustion turbines serving APS customer needs.

Retrospective Simulation of APS Supply & Demand With Alternative CT Plans

Change in Revenue Requirements from Base Case - Millions of Dollars

	Plan A Replace Redhawk & Sag SC With 50% EAs and 50% LM6000	Plan B Replace Redhawk & Sag SC With 152MW of EAs and 902MW of LM6000	Plan C Similar to Plan A with W. Phoenix CC 4&5 Replaced with LM6000
2003	12.3	20.6	27.3
2004	(4.6)	1.5	16.3
2005	(3.1)	3.2	22.0
2006	13.9	22.9	46.4
2007	18.8	27.0	56.5
2008	23.9	32.2	57.0
2009	19.3	26.3	47.1
2010	16.3	21.6	41.2
2011	21.7	25.3	43.6
2012	22.7	27.8	50.1
2013	34.6	39.6	70.3
2014	48.0	48.3	82.6
2015	37.9	37.3	70.3
2016	39.6	47.1	61.3
2017	41.6	38.0	70.1
2018	45.5	64.2	59.1
2019	48.0	114.4	60.0
2020	50.0	49.4	64.9
2021	55.6	63.2	90.3
2022	40.4	48.9	70.5
2023	34.1	41.8	50.7
2024	38.1	45.3	53.2
2025	38.4	45.4	53.9
2026	47.0	54.0	66.5
2027	82.3	89.4	124.5
2028	66.8	72.2	111.8
2029	56.4	62.3	89.9
2030	49.5	54.7	72.4
2031	49.6	54.3	72.5
2032	44.6	49.2	66.4
NPV 7.5% (2003-2032)	311.7	402.3	620.0

DCF Market Value of PWEC Assets - 1/1/2005
Based on Simulated Market Conditions
With Track B in 2005-2006
In Millions

	MARKET PRICES	APS Base (Genco) 7.00% COD 11.50% ROE	APS Requested 5.76% COD 11.50% ROE	ACC Staff Proposed 5.82% COD 9.00% ROE	RUCO Proposed 5.72% COD 9.50% ROE	Ratebase Cost as of 1/1/2005*
	I. With Annual Debt Repayment					
1	Fundamental	928	970	1,177	1,135	870
2	Cyclical	1,096	1,144	1,376	1,329	870
3	Underbuild	1,621	1,690	1,955	1,904	870
	II. With Balloon Debt Repayment					
4	Fundamental	1,089	1,162	1,380	1,340	870
5	Cyclical	1,280	1,367	1,607	1,565	870
6	Underbuild	1,882	2,006	2,274	2,232	870

Note * Ratebase at 7/1/2004 is $895 Million.

DCF Market Value of PWEC Assets - 1/1/2007
Based on Simulated Market Conditions
In Millions

	MARKET PRICES	APS Base (Genco) 7.00% COD 11.50% ROE	APS Requested 5.76% COD 11.50% ROE	ACC Staff Proposed 5.82% COD 9.00% ROE	RUCO Proposed 5.72% COD 9.50% ROE	Ratebase Cost as of 1/1/2007
	I. With Annual Debt Repayment					
1	Fundamental	1,100	1,147	1,344	1,305	825
2	Cyclical	1,318	1,373	1,590	1,547	825
3	Underbuild	1,966	2,045	2,273	2,230	825
	II. With Balloon Debt Repayment					
4	Fundamental	1,290	1,377	1,574	1,542	825
5	Cyclical	1,541	1,640	1,856	1,822	825
6	Underbuild	2,285	2,428	2,641	2,613	825

DCF Market Values of PWEC Assets

Based on 55% Debt, 45% Equity, 5.76% Cost of Debt and 11.50% ROE.
In Millions

	MARKET PRICES	Market Value As of	West Phoenix CC4	West Phoenix CC5	Redhawk CC12	Saguaro CT3	TOTAL
1	Fundamental Market						
2	With Track B in 2005-2006	1/1/2005	58	312	557	43	970
3		1/1/2007	68	365	664	51	1,147
4	Cyclical Market						
5	With Track B in 2005-2006	1/1/2005	68	366	661	48	1,144
6		1/1/2007	81	436	799	57	1,373
7	Underbuild Market						
8	With Track B in 2005-2006	1/1/2005	103	532	982	73	1,690
		1/1/2007	124	640	1,193	88	2,045
	RATE BASE						
		6/30/2004	67	263	536	30	895
		1/1/2005	65	256	521	29	870
		1/1/2007	59	234	506	26	825

Change (Increase) in DCF Market Value of PWEC Assets - 1/1/2005
With ACC Staff's Proposed Depreciation Schedule
In Millions

MARKET PRICES	APS Base (Genco) 7.00% COD 11.50% ROE	APS Requested 5.76% COD 11.50% ROE	ACC Staff Proposed 5.82% COD 9.00% ROE	RUCO Proposed 5.72% COD 9.50% ROE
Fundamental	93	109	140	135
Cyclical	106	123	158	153
Underbuild	144	170	208	204

DCF Market Value of Existing APS Generation Assets
Based on Simulated Cyclical Market Conditions
In Millions[1]
(As of 1/1/2005)

Assets	APS Base (Genco)	APS Requested	ACC Staff Proposed	RUCO Proposed
	7.00% COD 11.50% ROE	5.76% COD 11.50% ROE	5.82% COD 9.00% ROE	5.72% COD 9.50% ROE
Cholla 1-2-3	700	732	848	825
Four Corners 1-2-3	335	350	389	382
Four Corners 4-5	433	451	531	515
Navajo	567	584	664	649
Palo Verde	2,330	2,427	2,846	2,764
Ocotillo Steam	79	81	87	86
Saguaro Steam	74	76	81	80
West Phoenix CC 1-2-3	136	140	159	155
Ocotillo CT	55	56	61	60
Saguaro CT	54	55	59	58
West Phoenix CT	60	61	66	65
Yucca CT	78	79	85	84
Douglas CT	8	8	8	8
TOTAL	4,906	5,100	5,884	5,732

Note: (1) Versus $1.499 billion net book value less accumulated deferred income tax at 1/1/2005

DCF Market Value of APS Existing Generation Assets
Based on Fundamental Market Conditions
In Millions[1]
(As of 1/1/2005)

Assets	APS Base (Genco)	APS Requested	ACC Staff Proposed	RUCO Proposed
	7.00% COD 11.50% ROE	5.76% COD 11.50% ROE	5.82% COD 9.00% ROE	5.72% COD 9.50% ROE
Cholla 1-2-3	544	571	657	641
Four Corners 1-2-3	230	242	268	263
Four Corners 4-5	370	386	452	439
Navajo	497	513	583	570
Palo Verde	2,058	2,142	2,514	2,441
Ocotillo Steam	71	73	79	78
Saguaro Steam	68	70	74	74
West Phoenix CC 1-2-3	120	124	141	138
Ocotillo CT	51	52	56	55
Saguaro CT	50	51	55	54
West Phoenix CT	55	57	61	60
Yucca CT	71	73	78	77
Douglas CT	7	7	8	8
TOTAL	4,193	4,361	5,025	4,897

Note: (1) Versus $1.499 billion net book value less accumulated deferred income tax at 1/1/2005

Replacement Cost Summary Based on Alternative Resource Plans

PWEC Asset Revenue Requirements vs Alternative Resource Plans

Alternative		Plan Description:	Benefit / (Cost) (2005-2032) NPV - $Millions @Requested Cost of Capital	Original Study
Alternative	1	PWEC AZ Assets replaced with new CTs (600MW-7FA, 608MW-7EA, 533MW-LM6000)	463.2	463.2
Alternative	2	PWEC AZ Assets replaced with new CTs (608MW-7EA, 1107MW-LM6000)	622.0	622.0
Alternative	3	PWEC AZ Assets replaced with new CTs (608MW-7EA, 451MW-LM6000, 700MW-LMS100)	366.3	366.3
Alternative	4	Track B (2003-2006) / APS Builds Capacity Beginning 2007	(37.4)	(42.5)
Alternative	5	Track B (2003-2004) / APS Builds Capacity Beginning 2005	145.1	169.1
Alternative	6	Track B (2003-2006) / Everything purchased from Market starting in 2007	2478.8	2440.0
Alternative	7	Track B (2003-2004) / Everything purchased from Market starting in 2005	2688.5	2649.8
Alternative	8	Track B (2003-2006) / APS Builds Capacity Beginning 2006 (900MW CTs) / PWEC plants replaced with New Construction (1624MW CC/76MW CT) in 2007	37.8	(0.9)
Alternative	9	Track B (2003-2006) / 6X16 Purchases (2004-2007) / APS Builds Capacity Beginning 2006 (300MW CT) / PWEC plants replaced with New Construction (1019MW CC) in 2007 & (605MW CC/76MW CT) in 2008	72.5	33.8
Alternative	10	Track B (2003-2006) / APS Builds Capacity Beginning 2006 (900MW CTs) / PWEC plants replaced with New Construction (1129MW CC/76MW CT) in 2007 &(495MW CC) in 2010	60.5	21.8
Alternative	11	Track B (2003-2006) / APS Builds Capacity Beginning 2006 (900MW CTs) / PWEC plants replaced with New Construction (634MW CC/76MW CT) in 2007 & (990MW CC) in 2013	54.5	15.8
Alternative	12	Track B (2003-2006) / APS Builds Capacity Beginning 2006 (900MW CTs) / PWEC plants replaced with New Construction (634MW CC/76MW CT) in 2007	133.4	94.7

Description Of Alternative Resource Plans Used in The Replacement Cost Study

Base Case: APS long range forecast of loads & resources. Uses LRF prepared in August, 2003 as a reference case or base case for alternatives 1-3 and 6-12. A similar preliminary plan was used for alternatives 4&5.The base plan (s) assume continuation of the APS / PWEC Track –B contract through the summer of 2004. After that the units are assumed rate based.

Alternative#1 (To test PWEC CCs assets against new CTs): APS / PWEC Track-B contract continues through its term. PWEC assets were replaced with new Ct technology. New simple cycle (CTs) units were assumed permitted and built to serve APS load. with 608 MW GE-EA, 600 MW GE-7FA and 533 MW of LM6000 machines, scheduled to be on line between October 2005 and June 2010. These machines are approximately 70 MW, 150 MW and 50 MW respectively.

Alternative#2 (To test PWEC CCs assets against new CTs w/ Valley RMR concerns): APS / PWEC Track-B contract continues through its term. PWEC assets were replaced with new Ct technology with increased number of LM6000 units due to permitting and RMR concerns in the Valley. The PWEC units were replaced with 608 MW EA, and 1107 MW of LM6000 machines, scheduled to be on line between October 2005 and June 2010. Future 150MW 7FA machine advanced to 2006.

Alternative#3 (To test PWEC CCs assets against new CTs w/ technology efficiency gain): APS / PWEC Track-B contract continues through it term. PWEC assets were replaced with new Ct technology with more efficient newer GE LMS100 machines. The PWEC units were replaced with 608 MW EA, 451 MW of LM6000 and 500 MW LMS100 machines, scheduled to be on line between October 2005 and June 2009. Future 450MW 7FA Cts advanced to 2006-2007. The LMS100 machine is approximately 100 MW size and is designed to have a better heat rate than EA, 7FA or LM6000 machine.

Alternative#4 (To test replacing PWEC units with like kind): APS/ PWEC Track-B contract continues through its term. Alternative resource plan was developed to build new CC generation equivalent to the PWEC assets in 2007. This plan was designed to compare the value of rate-basing the PWEC plants at their embedded cost verses at reconstruction costs. The size and efficiency of the replacement assets were assumed to be the same as the original PWEC assets in this case. This alternate resource plan was prepared in April, 2003 just as the Track B contracts were awarded, therefore were not prepared as part of the formal resource planning process.

Description Of Alternative Resource Plans Used in The Replacement Cost Study

Alternative#5 (To test PWEC Units Rate basing VS Building New): This Alternative resource plan was developed to build new CC generation equivalent to the PWEC assets in 2005. This plan was designed to compare the value of rate-basing the PWEC plants at their embedded cost verses at reconstruction costs. The size and efficiency of the replacement assets were assumed to be the same as the original PWEC assets in this case. This alternate resource plan was prepared in April, 2003 just as the Track B contracts were awarded, therefore were not prepared as part of the formal resource planning process

Alternative #6 (To test total market dependence): This alternative was designed to see if APS customers would be better off if APS were buying all of its unmet needs after APS / PWEC Track-B contracts with wholesale market purchases based on GE-MAPS simulated prices rather than continuing an asset-backed ownership strategy. APS customers supply needs above the capabilities of the existing APS assets are met with market purchases and reflected an assumption of 100% access to a robust hourly market in making economy energy purchases.

Alternative #7 (To test total market dependence): This plan is similar to Alt 6 except the wholesale market purchases begin in 2005 and replace the short term Track B contracts. This plan again was designed to compare a market purchase strategy to an asset-backed ownership strategy.

Alternative #8 (Acc Staff Plan): This alternative plan continues the PWEC Track B contract until its termination and adds 900 MW of simple cycle turbines (7FA machines used) in summer of 2006. In summer 2007, an additional 1700 MW of generation capacity equivalent to the PWEC assets was assumed built. This plan was designed by ACC staff during discovery. This plan has increased reliance on the owned generation assets in 2006-2008 than the Company's 2003LRF base plan. After 2008 this plan mimics the base generation program in the APS 2003 LRF.

Alternate #9 (Acc Staff Plan): This resource plan was also designed by ACC Staff and consists of continuing the PWEC Track B contracts through their expiration in 2006. Staff requested 300 MW new Cts be installed in 2006. APS adds generation in 2007 & 2008 equivalent to the PWEC assets.. The market (6X16 summer purchases) fills 90% of all remaining summer capacity needs 2004 through 2007. After 2008 this plan mimics the generation program in the APS 2003 LRF.

Description Of Alternative Resource Plans Used in The Replacement Cost Study

Alternate #10 (Replace Redhawk #2 w/ Cts until 2010): This plan delays in-service schedule of Redhawk Units 2 until 2010. The alternative continues with PWEC Track B contracts through 2006. It adds 900 MW Cts (7GE FA machines) in 2006 as in alternate #6. Assumes that West Phoenix 4&5, Redhawk Unit 1 and Saguaro Ct3 were constructed in 2007. Alternate also relies on short-term market purchased power.

Alternate #11 (Replace Redhawk #1&2 with Cts and increase market purchase until 2013): This plan delays in-service schedule of Redhawk Units 1&2 until 2013. The alternative continues with PWEC Track-B contracts through 2006. It adds 900 MW Cts (GE 7FA machines) in 2006 as in alternate #10. Assumes that West Phoenix 4&5 and Saguaro Ct3 were constructed in 2007. Redhawk unit 1&2 was assumed constructed in 2013. Alternate also relies heavily on short-term market purchased power.

Alternative #12: (Replace Redhawk #1&2 with Cts permanently and increase market purchase): This plan delays in-service schedule of Redhawk Units 1&2 indefinitely. The alternative continues with PWEC Track B contracts through 2006. It adds 900 MW Cts (GE 7FA machines) in 2006 as in alternate #10. Assumes that West Phoenix 4&5 and Saguaro Ct3 were constructed in 2007.. Alternate also relies heavily on short-term market purchased power.

APS SUMMER SUPPLY & DEMAND BALANCE
Future Resources Summary

Base - August, 2003

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	5,723	6,023	6,269	6,522	6,787	7,064	7,357	7,667	7,914	8,127	8,393	8,691
2	ANNUAL LOAD GROWTH %		5.2	4.1	4.0	4.1	4.1	4.1	4.2	3.2	2.7	3.3	3.6
	RELIABILITY												
3	RESERVE REQUIREMENTS	743	787	823	860	898	939	981	1,027	1,062	1,093	1,132	1,175
4	TOTAL LOAD REQUIREMENTS	6,466	6,810	7,092	7,382	7,685	8,003	8,338	8,694	8,976	9,220	9,525	9,866
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
5	APS EXISTING GENERATION	3,981	4,007	4,002	4,029	4,029	4,055	4,055	4,055	4,055	4,055	4,055	4,055
6	SEASONAL VARIATION	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)
7	CAPACITY ON MAINTENANCE	-	-	-	-	-	-	-	-	-	-	-	-
8	TOTAL	3,927	3,953	3,948	3,975	3,975	4,001	4,001	4,001	4,001	4,001	4,001	4,001
	PURCHASED POWER RESOURCES												
9	SRP - FIRM	288	295	302	310	318	326	334	342	351	360	368	378
10	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
11	ENVIRONMENTAL PORTFOLIO	4	10	18	18	21	22	22	23	23	24	24	24
12	PACIFICORP DIV EXCH	480	480	480	480	480	480	480	480	480	480	480	480
13	TOTAL PURCHASES	834	847	862	870	881	890	898	907	916	926	934	944
14	TOTAL EXISTING RESOURCES	4,761	4,800	4,810	4,845	4,855	4,891	4,899	4,908	4,917	4,926	4,935	4,945
	C. EXISTING RESOURCES OVER / (UNDER)	(1,706)	(2,011)	(2,282)	(2,537)	(2,830)	(3,112)	(3,440)	(3,786)	(4,060)	(4,294)	(4,589)	(4,921)
	D. FUTURE RESOURCES												
15	W PHOENIX CC 4			110	110	110	110	110	110	110	110	110	110
16	W PHOENIX CC 5			524	524	524	524	524	524	524	524	524	524
17	REDHAWK CC 1-2			990	990	990	990	990	990	990	990	990	990
18	SAGUARO SC 3			76	76	76	76	76	76	76	76	76	76
19	PWEC TRACK B	1,700	1,700										
20	SUNDANCE TRACK B / SPOT PURCHASES	112	311	582	837	380	512	390	386	360	594	240	422
21	FUTURE RESOURCE NEEDS	0	0	0	0	750	900	1,350	1,700	2,000	2,000	2,650	2,800
22	TOTAL	1,812	2,011	2,282	2,537	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922
23	TOTAL EXISTING AND NEW RESOURCES	6,573	6,810	7,092	7,382	7,685	8,003	8,338	8,694	8,976	9,220	9,525	9,866
	E. TOTAL RESOURCES OVER / (UNDER)	106	0	0	0	0	0	0	0	0	0	0	0

APS SUMMER SUPPLY & DEMAND BALANCE
Future Resources Summary

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 1													
1	NEW SIMPLE CYCLE (EA)				304	456	532	532	608	608	608	608	608
2	NEW SIMPLE CYCLE (FA)				600	600	600	600	600	600	600	600	600
3	NEW SIMPLE CYCLE (LM6000)				533	533	533	533	533	533	533	533	533
4	PWEC TRACK B	1,700	1,700	1,700	1,700								
5	SUNDANCE TRACK B / SPOT PURCHASES	112	311	582	0	491	697	575	345	319	553	199	381
6	FUTURE RESOURCE NEEDS	0	0	0	0	750	750	1,200	1,700	2,000	2,000	2,650	2,800
7	TOTAL	1,812	2,011	2,282	3,137	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 2													
1	NEW SIMPLE CYCLE (EA)				152	456	532	532	608	608	608	608	608
2	NEW SIMPLE CYCLE (FA)				150	150	150	150	150	150	150	150	150
3	NEW SIMPLE CYCLE (LM6000)				943	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107
4	PWEC TRACK B	1,700	1,700	1,700	1,700								
5	SUNDANCE TRACK B / SPOT PURCHASES	112	311	582	0	367	573	451	371	345	579	225	407
6	FUTURE RESOURCE NEEDS	0	0	0	0	750	750	1,200	1,550	1,850	1,850	2,500	2,650
7	TOTAL	1,812	2,011	2,282	2,945	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 3													
1	NEW SIMPLE CYCLE (EA)				304	608	608	608	608	608	608	608	608
2	NEW SIMPLE CYCLE (FA)				300	450	450	450	450	450	450	450	450
3	NEW SIMPLE CYCLE (LM6000)					451	451	451	451	451	451	451	451
4	NEW SIMPLE CYCLE (LMS100)					200	300	400	400	500	500	500	600
5	PWEC TRACK B	1,700	1,700	1,700	1,700								
6	SUNDANCE TRACK B / SPOT PURCHASES	112	311	582	233	371	553	331	327	351	585	231	313
7	FUTURE RESOURCE NEEDS	0	0	0	0	750	750	1,200	1,550	1,700	1,700	2,350	2,500
8	TOTAL	1,812	2,011	2,282	2,537	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922

APS SUMMER SUPPLY & DEMAND BALANCE
Future Resources Summary

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 4													
1	VALLEY CC 4					112	112	112	112	112	112	112	112
2	VALLEY CC 5					506	506	506	506	506	506	506	506
3	CC 1-2 NEAR PALO VERDE					1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
4	CT 3					79	79	79	79	79	79	79	79
5	SEASONAL VARIATION					19	19	19	19	19	19	19	19
6	PWEC TRACK B	1,696	1,696	1,696	1,696								
7	SHORT TERM / SPOT PURCHASES	0	315	586	841	364	496	324	320	444	528	123	455
8	FUTURE RESOURCE NEEDS	0	0	0	0	750	900	1,400	1,750	1,900	2,050	2,750	2,750
9	TOTAL	1,696	2,011	2,282	2,537	2,830	3,112	3,440	3,786	4,060	4,294	4,589	4,921

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 5													
1	VALLEY CC 4			112	112	112	112	112	112	112	112	112	112
2	VALLEY CC 5			506	506	506	506	506	506	506	506	506	506
3	CC 1-2 NEAR PALO VERDE			1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
4	CT 3			79	79	79	79	79	79	79	79	79	79
5	SEASONAL VARIATION			19	19	19	19	19	19	19	19	19	19
6	PWEC TRACK B	1,696	1,696										
7	SHORT TERM / SPOT PURCHASES	0	315	566	821	364	496	324	320	444	528	123	455
8	FUTURE RESOURCE NEEDS	0	0	0	0	750	900	1,400	1,750	1,900	2,050	2,750	2,750
9	TOTAL	1,696	2,011	2,282	2,537	2,830	3,112	3,440	3,786	4,060	4,294	4,589	4,921

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 6													
1	PWEC TRACK B	1,700	1,700	1,700	1,700								
2	SUNDANCE TRACK B / SPOT PURCHASES	112	311	582	837	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922
3	TOTAL	1,812	2,011	2,282	2,537	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922

APS SUMMER SUPPLY & DEMAND BALANCE
Future Resources Summary

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 7													
1	PWEC TRACK B	1,700	1,700										
2	SUNDANCE TRACK B / SPOT PURCHASES	112	311	2,282	2,537	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922
3	TOTAL	1,812	2,011	2,282	2,537	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 8													
1	W. PHOENIX CC 4 - NEW					110	110	110	110	110	110	110	110
2	W. PHOENIX CC 5 - NEW					524	524	524	524	524	524	524	524
3	REDHAWK CC 1-2 - NEW					990	990	990	990	990	990	990	990
4	SAGUARO SC3 - NEW					76	76	76	76	76	76	76	76
5	NEW SIMPLE CYCLE CT				900	900	900	900	900	900	900	900	900
6	PWEC TRACK B	1,700	1,700	1,700	1,700								
7	SUNDANCE TRACK B / SPOT PURCHASES	112	311	582	0	230	512	390	386	360	594	240	422
8	FUTURE RESOURCE NEEDS	0	0	0	0	0	0	450	800	1,100	1,100	1,750	1,900
9	TOTAL	1,812	2,011	2,282	2,600	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 9													
1	W. PHOENIX CC 4 - NEW						110	110	110	110	110	110	110
2	W. PHOENIX CC 5 - NEW					524	524	524	524	524	524	524	524
3	REDHAWK CC 1-2 - NEW					495	990	990	990	990	990	990	990
4	SAGUARO SC3 - NEW						76	76	76	76	76	76	76
5	NEW SIMPLE CYCLE CT				300	300	300	300	300	300	300	300	300
6	PWEC TRACK B	1,700	1,700	1,700	1,700								
7	6X16 MARKET PURCHASE		145	389	483	800							
8	SUNDANCE TRACK B / SPOT PURCHASES	112	166	193	54	111	512	390	386	360	594	240	422
9	FUTURE RESOURCE NEEDS	0	0	0	0	600	600	1,050	1,400	1,700	1,700	2,350	2,500
10	TOTAL	1,812	2,011	2,282	2,537	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922

APS SUMMER SUPPLY & DEMAND BALANCE
Future Resources Summary

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 10													
1	W. PHOENIX CC 4 - NEW					110	110	110	110	110	110	110	110
2	W. PHOENIX CC 5 - NEW					524	524	524	524	524	524	524	524
3	REDHAWK CC 1-2 - NEW					495	495	495	990	990	990	990	990
4	SAGUARO SC3 - NEW					76	76	76	76	76	76	76	76
5	NEW SIMPLE CYCLE CT				900	900	900	900	900	900	900	900	900
6	PWEC TRACK B	1,700	1,700	1,700	1,700								
7	SUNDANCE TRACK B / SPOT PURCHASES	112	311	582	0	275	557	885	386	360	594	240	422
8	FUTURE RESOURCE NEEDS	0	0	0	0	450	450	450	800	1,100	1,100	1,750	1,900
9	TOTAL	1,812	2,011	2,282	2,600	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 11													
1	W. PHOENIX CC 4 - NEW					110	110	110	110	110	110	110	110
2	W. PHOENIX CC 5 - NEW					524	524	524	524	524	524	524	524
3	REDHAWK CC 1-2 - NEW											990	990
4	SAGUARO SC3 - NEW					76	76	76	76	76	76	76	76
5	NEW SIMPLE CYCLE CT				900	900	900	900	900	900	900	900	900
6	PWEC TRACK B	1,700	1,700	1,700	1,700								
7	SUNDANCE TRACK B / SPOT PURCHASES	112	311	582	0	170	452	780	776	1,050	1,284	240	422
8	FUTURE RESOURCE NEEDS	0	0	0	0	1,050	1,050	1,050	1,400	1,400	1,400	1,750	1,900
9	TOTAL	1,812	2,011	2,282	2,600	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 12													
1	W. PHOENIX CC 4 - NEW					110	110	110	110	110	110	110	110
2	W. PHOENIX CC 5 - NEW					524	524	524	524	524	524	524	524
3	REDHAWK CC 1-2 - NEW												
4	SAGUARO SC3 - NEW					76	76	76	76	76	76	76	76
5	NEW SIMPLE CYCLE CT				900	900	900	900	900	900	900	900	900
6	PWEC TRACK B	1,700	1,700	1,700	1,700								
7	SUNDANCE TRACK B / SPOT PURCHASES	112	311	582	0	170	452	330	326	300	534	180	362
8	FUTURE RESOURCE NEEDS	0	0	0	0	1,050	1,050	1,500	1,850	2,150	2,150	2,800	2,950
9	TOTAL	1,812	2,011	2,282	2,600	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922

Replacement Cost Summary Based on Alternative Resource Plans

Change in Revenue Requirements from Base Case - Millions of Dollars

	Alternative 1	Alternative 2	Alternative 3
2005	(124.3)	(120.9)	(124.0)
2006	4.0	(8.0)	(66.0)
2007	62.5	69.6	14.3
2008	47.0	54.9	29.5
2009	32.4	47.9	28.5
2010	24.0	46.1	38.2
2011	40.0	55.4	43.1
2012	44.2	63.3	48.5
2013	66.3	82.6	72.4
2014	78.5	92.4	70.1
2015	60.8	82.7	59.6
2016	50.3	53.5	59.0
2017	73.6	92.9	80.0
2018	63.6	67.0	71.1
2019	69.4	115.7	69.9
2020	64.4	76.8	56.7
2021	78.8	104.0	77.5
2022	49.3	53.7	46.5
2023	34.0	76.5	38.0
2024	45.8	54.3	50.4
2025	59.0	72.7	51.6
2026	67.9	106.8	65.0
2027	110.8	118.7	140.8
2028	128.1	178.2	149.3
2029	101.7	115.3	105.6
2030	103.3	127.9	71.3
2031	107.8	131.8	75.4
2032	92.2	111.2	92.4
NPV 7.5%			
(2005-2032)	463.2	622.0	366.3
(2007-2032)	664.9	856.7	622.6

Replacement Cost Summary Based on Alternative Resource Plans

Based on APS' Requested Cost of Capital
PWEC Plants Capital Structure - 55% Debt @5.76%

Change in Revenue Requirements from Base Case - Millions of Dollars

	Alternative 4	Alternative 5
2003	0.0	0.0
2004	0.0	0.0
2005	(129.6)	(7.3)
2006	(187.0)	12.8
2007	9.2	13.5
2008	7.2	11.3
2009	18.7	0.5
2010	32.3	11.3
2011	21.6	29.5
2012	35.0	20.5
2013	31.2	21.0
2014	25.3	12.4
2015	52.2	19.3
2016	42.8	41.4
2017	15.8	6.9
2018	48.1	8.8
2019	33.7	9.5
2020	8.4	19.9
2021	17.6	5.7
2022	37.2	7.7
2023	16.9	18.8
2024	25.2	7.9
2025	35.5	20.4
2026	15.1	11.9
2027	29.8	8.4
2028	28.5	17.4
2029	14.9	9.4
2030	28.8	5.1
2031	24.9	12.4
2032	3.5	0.3
NPV 7.5%		
(2003-2032)	(32.4)	125.6
(2005-2032)	(37.4)	145.1
(2007-2032)	283.1	162.7

Replacement Cost Summary Based on Alternative Resource Plans

Based on Original Study Cost of Capital
PWEC Plants Capital Structure - 50% Debt @6.25%

Change in Revenue Requirements from Base Case - Millions of Dollars

	Alternative 4	Alternative 5
2003	0.0	0.0
2004	0.0	0.0
2005	(143.3)	(1.6)
2006	(200.2)	18.2
2007	16.3	18.4
2008	13.2	15.7
2009	24.4	4.4
2010	37.8	15.3
2011	26.8	33.8
2012	40.2	24.6
2013	36.4	25.0
2014	30.6	16.0
2015	57.7	23.0
2016	48.1	45.1
2017	20.4	9.9
2018	52.5	11.4
2019	37.9	11.7
2020	11.9	22.3
2021	20.7	7.6
2022	40.3	9.2
2023	19.7	20.5
2024	28.2	9.5
2025	38.4	22.3
2026	17.6	13.7
2027	32.5	9.8
2028	31.0	18.7
2029	16.9	10.3
2030	30.9	5.7
2031	26.7	13.6
2032	4.5	0.7
NPV 8.6%		
(2003-2032)	(36.0)	143.5
(2005-2032)	(42.5)	169.1
(2007-2032)	305.6	182.9

Replacement Cost Summary Based on Alternative Resource Plans

Based on APS' Requested Cost of Capital
PWEC Plants Capital Structure - 55% Debt @5.76%

Change in Revenue Requirements from Base Case - Millions of Dollars

	Alternative 6	Alternative 7	Alternative 8	Alternative 9	Alternative 10	Alternative 11	Alternative 12
2005	(184.1)	(102.6)	(184.1)	(183.6)	(184.1)	(184.1)	(184.1)
2006	(159.3)	(4.5)	(162.6)	(133.0)	(162.6)	(162.5)	(162.6)
2007	195.6	195.6	37.5	(5.5)	26.5	1.9	(6.0)
2008	154.1	154.1	7.6	12.3	16.3	18.2	14.1
2009	2.8	2.8	18.4	16.7	28.3	33.3	17.5
2010	(85.7)	(85.7)	28.6	34.6	23.9	(0.6)	17.5
2011	(103.2)	(103.2)	25.7	28.5	24.4	4.6	28.5
2012	(82.9)	(82.9)	43.2	41.4	41.0	13.5	43.2
2013	163.0	163.0	42.5	47.5	41.3	40.2	38.5
2014	548.0	548.0	32.8	45.0	28.5	22.3	38.6
2015	596.1	596.1	84.2	68.8	80.8	71.8	62.2
2016	150.9	150.9	34.0	56.1	58.2	82.4	62.7
2017	56.3	56.3	13.6	26.8	22.2	22.3	31.1
2018	(27.5)	(27.5)	58.7	60.4	44.0	38.3	56.9
2019	65.9	65.9	43.8	51.6	41.9	60.6	58.1
2020	545.6	545.6	19.4	28.2	26.9	28.5	42.3
2021	1,261.8	1,261.8	55.5	41.1	72.6	83.5	95.0
2022	1,152.5	1,152.5	19.9	46.0	34.8	51.7	68.6
2023	432.1	432.1	19.9	28.1	22.1	35.1	43.3
2024	53.3	53.3	34.9	34.0	18.0	54.4	60.4
2025	54.1	54.1	41.6	47.5	50.5	60.0	62.5
2026	151.9	151.9	63.0	50.5	67.0	68.2	96.1
2027	807.5	807.5	45.0	70.2	64.4	96.5	128.1
2028	1,610.8	1,610.8	65.4	71.2	73.0	95.0	123.7
2029	1,502.8	1,502.8	55.5	62.6	40.8	57.4	106.8
2030	886.4	886.4	71.4	67.4	78.4	91.6	105.9
2031	469.3	469.3	98.9	81.7	103.4	110.7	143.4
2032	422.5	422.5	(45.5)	7.0	(8.3)	45.3	81.6
NPV 7.5%							
(2005-2032)	2,478.8	2,688.5	37.8	72.5	60.5	54.5	133.4
(2007-2032)	3,221.7	3,221.7	404.2	414.2	430.5	423.4	514.7

Replacement Cost Summary Based on Alternative Resource Plans

Based on Original Study Cost of Capital
PWEC Plants Capital Structure - 55% Debt @7%

Change in Revenue Requirements from Base Case - Millions of Dollars

	Alternative 6	Alternative 7	Alternative 8	Alternative 9	Alternative 10	Alternative 11	Alternative 12
2005	(190.0)	(108.5)	(190.0)	(189.5)	(190.0)	(190.0)	(190.0)
2006	(164.8)	(10.0)	(168.2)	(138.6)	(168.2)	(168.1)	(168.1)
2007	190.4	190.4	32.3	(10.7)	21.2	(3.4)	(11.3)
2008	149.1	149.1	2.7	7.3	11.4	13.3	9.2
2009	(1.8)	(1.8)	13.7	12.1	23.6	28.7	12.8
2010	(90.1)	(90.1)	24.2	30.3	19.5	(5.0)	13.1
2011	(107.3)	(107.3)	21.7	24.4	20.3	0.5	24.4
2012	(86.7)	(86.7)	39.4	37.6	37.2	9.7	39.4
2013	159.5	159.5	39.0	44.0	37.8	36.7	35.0
2014	544.7	544.7	29.5	41.8	25.3	19.0	35.3
2015	593.1	593.1	81.2	65.9	77.8	68.9	59.3
2016	148.2	148.2	31.3	53.4	55.6	79.7	60.0
2017	53.9	53.9	11.2	24.4	19.8	19.9	28.7
2018	(29.6)	(29.6)	56.6	58.3	41.9	36.2	54.8
2019	64.1	64.1	42.0	49.8	40.0	58.8	56.3
2020	544.0	544.0	17.8	26.6	25.4	26.9	40.8
2021	1,260.5	1,260.5	54.3	39.8	71.3	82.3	93.8
2022	1,151.5	1,151.5	18.9	45.0	33.8	50.7	67.6
2023	431.3	431.3	19.1	27.2	21.3	34.3	42.5
2024	52.7	52.7	34.2	33.4	17.3	53.8	59.8
2025	53.7	53.7	41.2	47.0	50.0	59.5	62.0
2026	151.7	151.7	62.7	50.3	66.7	68.0	95.9
2027	807.4	807.4	44.9	70.1	64.3	96.3	128.0
2028	1,610.6	1,610.6	65.2	71.0	72.9	94.9	123.6
2029	1,502.7	1,502.7	55.4	62.5	40.7	57.3	106.7
2030	886.3	886.3	71.4	67.3	78.3	91.6	105.8
2031	469.2	469.2	98.9	81.7	103.3	110.7	143.3
2032	422.4	422.4	(45.6)	6.9	(8.4)	45.2	81.5
NPV 7.5%							
(2005-2032)	2,440.0	2,649.8	(0.9)	33.8	21.8	15.8	94.7
(2007-2032)	3,188.8	3,188.8	371.3	381.3	397.6	390.6	481.8

Annual Busbar Cost of Offered PPAs Versus PWEC Units

Annual Busbar Cost of Offered and Simulated PPAs

PPA Levelized Busbar Cost Results

($/MWH)

APS 2003 – 04 RFP PPA Result Summary

30 Yr. Levelized Busbar Costs of Offered PPAs and PWEC

DCF Market Value of PWEC Assets - 1/1/2005
Based on PPA Data in RFP Market Conditions
With Track B in 2005-2006
In Millions

	MARKET PRICES	APS Base (Genco) 7.00% COD 11.50% ROE	APS Requested 5.76% COD 11.50% ROE	ACC Staff Proposed 5.82% COD 9.00% ROE	RUCO Proposed 5.72% COD 9.50% ROE	Ratebase Cost as of 1/1/2005*
	I. With Annual Debt Repayment					
1	Average of Four Lowest PPA's	1,034	1,081	1,297	1,254	870
2	Average of Three PPA's (Comb. #1)	1,017	1,062	1,278	1,235	870
3	Average of Three PPA's (Comb. #2)	1,025	1,071	1,281	1,240	870
4	Representation of PPA	917	957	1,153	1,113	870
	II. With Balloon Debt Repayment					
5	Average of Four Lowest PPA's	1,210	1,293	1,517	1,478	870
6	Average of Three PPA's (Comb. #1)	1,190	1,271	1,497	1,457	870
7	Average of Three PPA's (Comb. #2)	1,200	1,283	1,500	1,463	870
8	Representation of PPA	1,074	1,149	1,351	1,315	870

Note * Ratebase at 7/1/2004 is $895 Million.

DCF Market Value of PWEC Assets - 1/1/2007
Based on PPA Data in RFP Market Conditions
In Millions

	MARKET PRICES	APS Base (Genco) 7.00% COD 11.50% ROE	APS Requested 5.76% COD 11.50% ROE	ACC Staff Proposed 5.82% COD 9.00% ROE	RUCO Proposed 5.72% COD 9.50% ROE	Ratebase Cost as of 1/1/2007
	I. With Annual Debt Repayment					
1	Average of Four Lowest PPA's	1,231	1,282	1,485	1,446	825
2	Average of Three PPA's (Comb. #1)	1,209	1,260	1,463	1,423	825
3	Average of Three PPA's (Comb. #2)	1,220	1,271	1,466	1,428	825
4	Representation of PPA	1,085	1,132	1,315	1,279	825
	II. With Balloon Debt Repayment					
5	Average of Four Lowest PPA's	1,439	1,533	1,733	1,703	825
6	Average of Three PPA's (Comb. #1)	1,415	1,510	1,710	1,680	825
7	Average of Three PPA's (Comb. #2)	1,428	1,523	1,716	1,684	825
8	Representation of PPA	1,273	1,359	1,540	1,513	825

DCF Market Values of PWEC Assets

Based on 55% Debt, 45% Equity, 5.76% Cost of Debt and 11.50% ROE.
In Millions

	MARKET PRICES	Market Value As of	West Phoenix CC4	West Phoenix CC5	Redhawk CC12	Saguaro CT3	TOTAL
1	Average of Four Lowest PPA's						
2	With Track B in 2005-2006	1/1/2005	63	343	632	43	1,081
3		1/1/2007	74	403	755	51	1,282
4	Average of Three PPA's (Comb. #1)						
5	With Track B in 2005-2006	1/1/2005	62	337	620	43	1,062
		1/1/2007	73	396	741	51	1,260
6	Average of Three PPA's (Comb. #2)						
7	With Track B in 2005-2006	1/1/2005	62	340	626	43	1,071
8		1/1/2007	73	400	748	51	1,271
9	Representation of Lowest PPA						
10	With Track B in 2005-2006	1/1/2005	57	303	555	43	957
11		1/1/2007	66	354	662	51	1,132

RATE BASE					
6/30/2004	67	263	536	30	895
1/1/2005	65	256	521	29	870
1/1/2007	59	234	506	26	825

Replacement Cost Summary Based on Using RFP PPA Data

PWEC Asset Revenue Requirements vs Alternative Resource Plans Based on PPA

Prospective Alternatives		Plan Description:	2005-2032 [1] NPV $Million
Alternative	13	W. Phx CC 4&5 Priced @Low end representative PPA / Redhawk replaced with new CTs	312.2
Alternative	14	W. Phx CC 4&5 Priced @Average of 2 PPAs / Redhawk replaced with new CTs	457.3
Alternative	15	W. Phx CC 4&5 Priced @Highest of 2 PPAs / Redhawk replaced with new CTs	511.0
Alternative	16	PWEC AZ Assets Priced @Low end representative PPA	362.1
Alternative	17	PWEC AZ Assets Priced @Average of 4 PPAs	784.1
Alternative	18	PWEC AZ Assets Priced @4th Highest PPA	893.3

Note: (1) Value above rate base cost. Comparison of Base plan 2003 LRF in which PWEC units are rate based vs prospective alternative resource plans with combustion turbines serving APS customer needs. Track B contract in 2005 and 2006.

Description Of Alternative Resource Plans Used in The Replacement Cost Study

Base Case: APS long range forecast of loads & resources. Uses LRF prepared in August, 2003 as a reference case or base case for alternatives 1-3 and 6-12. A similar preliminary plan was used for alternatives 4&5:The base plan (s) assume continuation of the APS / PWEC Track –B contract through the summer of 2004. After that the units are assumed rate based.

Alternative #13: (Replace Redhawk #1&2 with Cts / Price West Phoenix 4&5 with lowest cost - APS RFP-PPAs): This alternative plan continues with APS / PWEC Track-B contract until its expiration term. Replaces Redhawk 1&2 with mix of Ct technology staring in 2006. One unit at Redhawk is replaced with EA machines and the second with LM6000s by summer 2007. West Phoenix 4&5 priced at the lowest end of APS RFP –PPA data.

Alternative #14: (Replace Redhawk #1&2 with Cts / Price West Phoenix 4&5 with average cost of two - APS RFP-PPAs): This alternative plan continues with APS / PWEC Track-B contract until its expiration term. Replaces Redhawk 1&2 with mix of Ct technology staring in 2006. One unit at Redhawk is replaced with EA machines and the second with LM6000s by summer 2007. West Phoenix 4&5 priced at the average of APS RFP – two PPAs data

Alternative #15: (Replace Redhawk #1&2 with Cts / Price West Phoenix 4&5 with 2nd highest cost - APS RFP-PPAs): This alternative plan continues with APS / PWEC Track-B contract until its expiration term. Replaces Redhawk 1&2 with mix of Ct technology staring in 2006. One unit at Redhawk is replaced with EA machines and the second with LM6000s by summer 2007. West Phoenix 4&5 priced at 2nd highest of APS RFP – PPAs data.

Alternative #16: (Redhawk #1&2 & West Phoenix 4&5 priced with lowest cost -APS RFP PPAs).

Alternative #17: (Redhawk #1&2 & West Phoenix 4&5 priced with average cost of two -APS RFP PPAs).

Alternative #18: (Redhawk #1&2 & West Phoenix 4&5 priced with average cost 2nd highest cost -APS RFP PPAs).

APS SUMMER SUPPLY & DEMAND BALANCE

Future Resources Summary

Base - August, 2003

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	5,723	6,023	6,269	6,522	6,787	7,064	7,357	7,667	7,914	8,127	8,393	8,691
2	ANNUAL LOAD GROWTH %		5.2	4.1	4.0	4.1	4.1	4.1	4.2	3.2	2.7	3.3	3.6
	RELIABILITY												
3	RESERVE REQUIREMENTS	743	787	823	860	898	939	981	1,027	1,062	1,093	1,132	1,175
4	TOTAL LOAD REQUIREMENTS	6,466	6,810	7,092	7,382	7,685	8,003	8,338	8,694	8,976	9,220	9,525	9,866
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
5	APS EXISTING GENERATION	3,981	4,007	4,002	4,029	4,029	4,055	4,055	4,055	4,055	4,055	4,055	4,055
6	SEASONAL VARIATION	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)
7	CAPACITY ON MAINTENANCE	-	-	-	-	-	-	-	-	-	-	-	-
8	TOTAL	3,927	3,953	3,948	3,975	3,975	4,001	4,001	4,001	4,001	4,001	4,001	4,001
	PURCHASED POWER RESOURCES												
9	SRP - FIRM	288	295	302	310	318	326	334	342	351	360	368	378
10	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
11	ENVIRONMENTAL PORTFOLIO	4	10	18	18	21	22	22	23	23	24	24	24
12	PACIFICORP DIV EXCH	480	480	480	480	480	480	480	480	480	480	480	480
13	TOTAL PURCHASES	834	847	862	870	881	890	898	907	916	926	934	944
14	TOTAL EXISTING RESOURCES	4,761	4,800	4,810	4,845	4,855	4,891	4,899	4,908	4,917	4,926	4,935	4,945
	C. EXISTING RESOURCES OVER / (UNDER)	(1,706)	(2,011)	(2,282)	(2,537)	(2,830)	(3,112)	(3,440)	(3,786)	(4,060)	(4,294)	(4,589)	(4,921)
	D. FUTURE RESOURCES												
15	W PHOENIX CC 4			110	110	110	110	110	110	110	110	110	110
16	W PHOENIX CC 5			524	524	524	524	524	524	524	524	524	524
17	REDHAWK CC 1-2			990	990	990	990	990	990	990	990	990	990
18	SAGUARO SC 3			76	76	76	76	76	76	76	76	76	76
19	PWEC TRACK B	1,700	1,700										
20	SUNDANCE TRACK B / SPOT PURCHASES	112	311	582	837	380	512	390	386	360	594	240	422
21	FUTURE RESOURCE NEEDS	0	0	0	0	750	900	1,350	1,700	2,000	2,000	2,650	2,800
22	TOTAL	1,812	2,011	2,282	2,537	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922
23	TOTAL EXISTING AND NEW RESOURCES	6,573	6,810	7,092	7,382	7,685	8,003	8,338	8,694	8,976	9,220	9,525	9,866
	E. TOTAL RESOURCES OVER / (UNDER)	106	0	0	0	0	0	0	0	0	0	0	0

APS SUMMER SUPPLY & DEMAND BALANCE

Future Resources Summary

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 13, 14, 15													
1	W. PHOENIX CC 4&5 PPA					634	634	634	634	634	634	634	634
2	NEW SIMPLE CYCLE (EA)				228	532	532	532	532	532	532	532	532
3	NEW SIMPLE CYCLE (LM6000)				123	533	533	533	533	533	533	533	533
4	PWEC TRACK B	1,700	1,700	1,700	1,700								
5	SUNDANCE TRACK B / SPOT PURCHASES	112	311	582	486	381	513	391	387	361	595	241	423
6	FUTURE RESOURCE NEEDS	0	0	0	0	750	900	1,350	1,700	2,000	2,000	2,650	2,800
7	TOTAL	1,812	2,011	2,282	2,537	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALTERNATIVE 16, 17, 18													
1	REPLACE W. PHOENIX CC 4 w/PPA					110	110	110	110	110	110	110	110
2	REPLACE W. PHOENIX CC 5 w/PPA					524	524	524	524	524	524	524	524
3	REPLACE REDHAWK CC 1&2 w/PPA					1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
4	REPLACE SAGUARO SC3 w/ 7EA					76	76	76	76	76	76	76	76
5	PWEC TRACK B	1,700	1,700	1,700	1,700								
6	SUNDANCE TRACK B / SPOT PURCHASES	112	311	582	837	370	502	380	376	350	584	230	412
7	FUTURE RESOURCE NEEDS	0	0	0	0	750	900	1,350	1,700	2,000	2,000	2,650	2,800
8	TOTAL	1,812	2,011	2,282	2,537	2,830	3,112	3,440	3,786	4,060	4,294	4,590	4,922

Replacement Cost Summary Based on Using RFP Data

Change in Revenue Requirements from Base Case - Millions of Dollars

	Alternative 13	Alternative 14	Alternative 15	Alternative 16	Alternative 17	Alternative 18
2005	(124.0)	(124.0)	(124.0)	(124.0)	(124.0)	(124.0)
2006	(97.6)	(97.6)	(97.6)	(111.2)	(111.2)	(111.2)
2007	21.2	27.9	34.9	48.1	68.6	90.8
2008	37.1	43.4	50.0	33.3	53.1	72.1
2009	37.1	43.8	50.7	37.6	58.3	76.1
2010	35.5	41.8	48.3	39.3	59.9	76.5
2011	38.6	44.7	51.0	44.7	65.6	80.6
2012	47.1	53.1	59.2	51.3	73.5	87.4
2013	61.0	67.4	73.9	57.5	80.7	93.5
2014	76.0	81.6	87.4	65.1	88.9	100.5
2015	61.7	67.4	73.2	69.3	93.8	104.0
2016	70.3	76.3	82.5	85.7	112.0	120.9
2017	65.8	71.9	78.0	79.5	107.1	114.9
2018	78.0	83.4	89.0	97.8	125.9	132.4
2019	80.8	85.7	90.7	99.3	128.0	133.3
2020	76.8	81.4	86.1	92.4	122.1	126.2
2021	84.6	89.5	94.5	94.7	125.4	128.3
2022	64.1	69.0	74.1	95.2	127.3	129.2
2023	64.3	69.1	74.2	108.8	142.3	143.1
2024	69.0	73.8	78.8	115.3	150.2	150.0
2025	70.3	75.1	80.0	118.4	154.7	153.7
2026	81.6	86.4	91.3	129.7	167.6	165.7
2027	63.7	137.5	139.7	38.9	205.7	200.8
2028	47.1	144.4	144.4	(17.5)	191.1	201.4
2029	33.5	134.1	134.1	(24.2)	191.6	202.0
2030	20.8	125.0	125.0	(28.6)	194.6	205.0
2031	12.2	120.0	120.0	(36.3)	194.5	204.8
2032	(2.8)	108.8	108.8	(51.9)	186.8	196.8
NPV 7.5%						
(2005-2032)	312.2	457.3	511.0	362.1	784.1	893.3
(2007-2032)	591.7	759.4	821.5	663.0	1,150.6	1,276.7

Summary of Projected RCN of PWEC Assets at 1/1/2005 Price Levels

	Redhawk			West Phoenix CC4			West Phoenix CC5		Saguaro CT 3			TOTAL
	Units 1&2	Transm	Total	WP CC4	Transm	Total	WP CC5	Total	Sag CT 3	Transm	Total	PWEC
12/31/2002 RCN (Note 1)	548.5	49.0	597.5	78.1	2.0	80.1	308.6	308.6	35.3	1.8	37.1	1023.3
Annual Escalation Rate	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	
12/31/2004 RCN	565.0	50.5	615.5	80.5	2.0	82.5	318.0	318.0	36.4	1.8	38.2	1054.2
Capacity MW			990			110		524			76	1700
$/kW			622			750		607			503	620

Note 1: RCN at 12/31/2002 for PWEC Assets (See WP LLR 4)

PWEC RCN GENERATION AT 1/1/2005
CHANGE IN REVENUE REQUIREMENTS
In Millions

	@5.76% COD 11.50% ROE	@7.00% COD 11.50% ROE
2005	11.7	18.9
2006	7.0	13.9
2007	12.2	18.7
2008	12.5	18.7
2009	14.8	20.7
2010	18.4	24.0
2011	22.0	27.3
2012	21.7	26.7
2013	21.3	26.1
2014	21.0	25.4
2015	20.6	24.7
2016	20.2	24.0
2017	20.0	23.6
2018	19.6	22.9
2019	19.2	22.2
2020	18.9	21.6
2021	18.5	21.0
2022	18.0	20.2
2023	16.2	18.1
2024	14.1	15.7
2025	14.5	15.9
2026	40.2	41.4
2027	48.5	49.5
2028	20.1	20.8
2029	7.4	8.0
2030	7.0	7.6
2031	5.8	6.4
2032	3.1	3.7
Total	**494.5**	**587.6**
NPV@ 7.5%	**195.5**	**247.8**

CPW OF NET BENEFITS OF RATEBASING PWEC UNITS USING AVERAGE OF OFFERED RFP PPA DATA

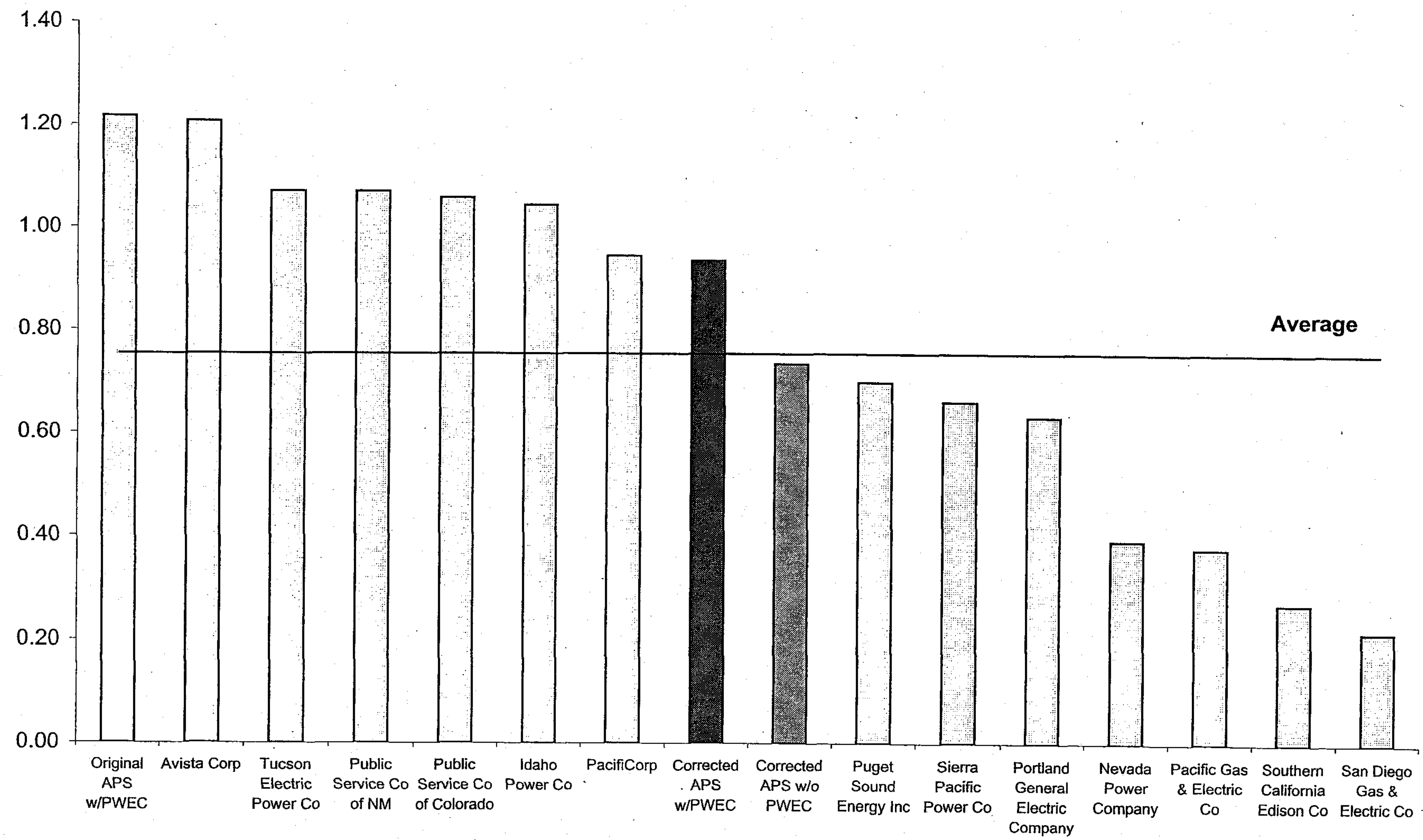
CPW OF NET BENEFITS OF RATEBASING PWEC UNITS

FUNDAMENTAL MARKET

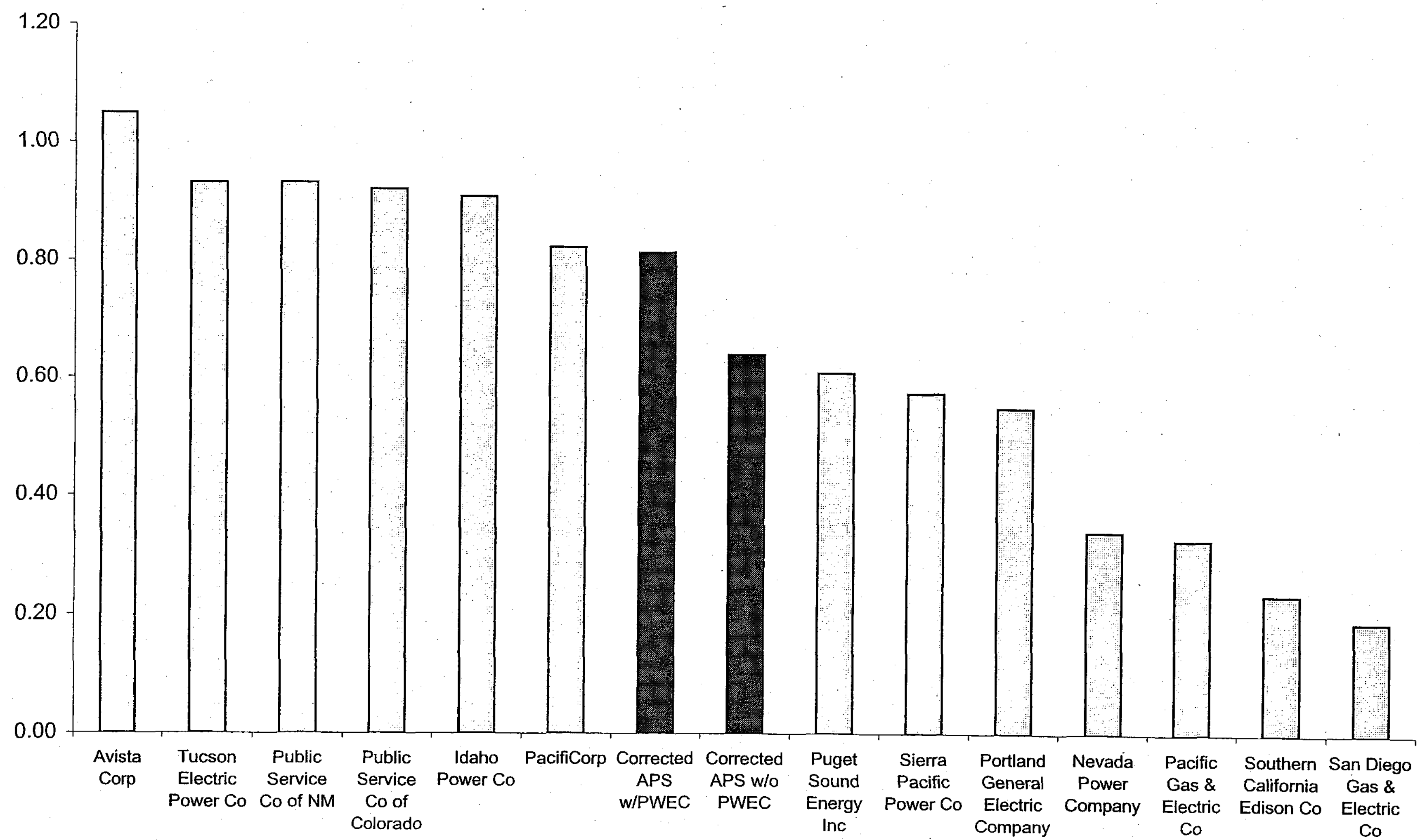
Market Value of PWEC Assets - Schlissel's Market

In Millions

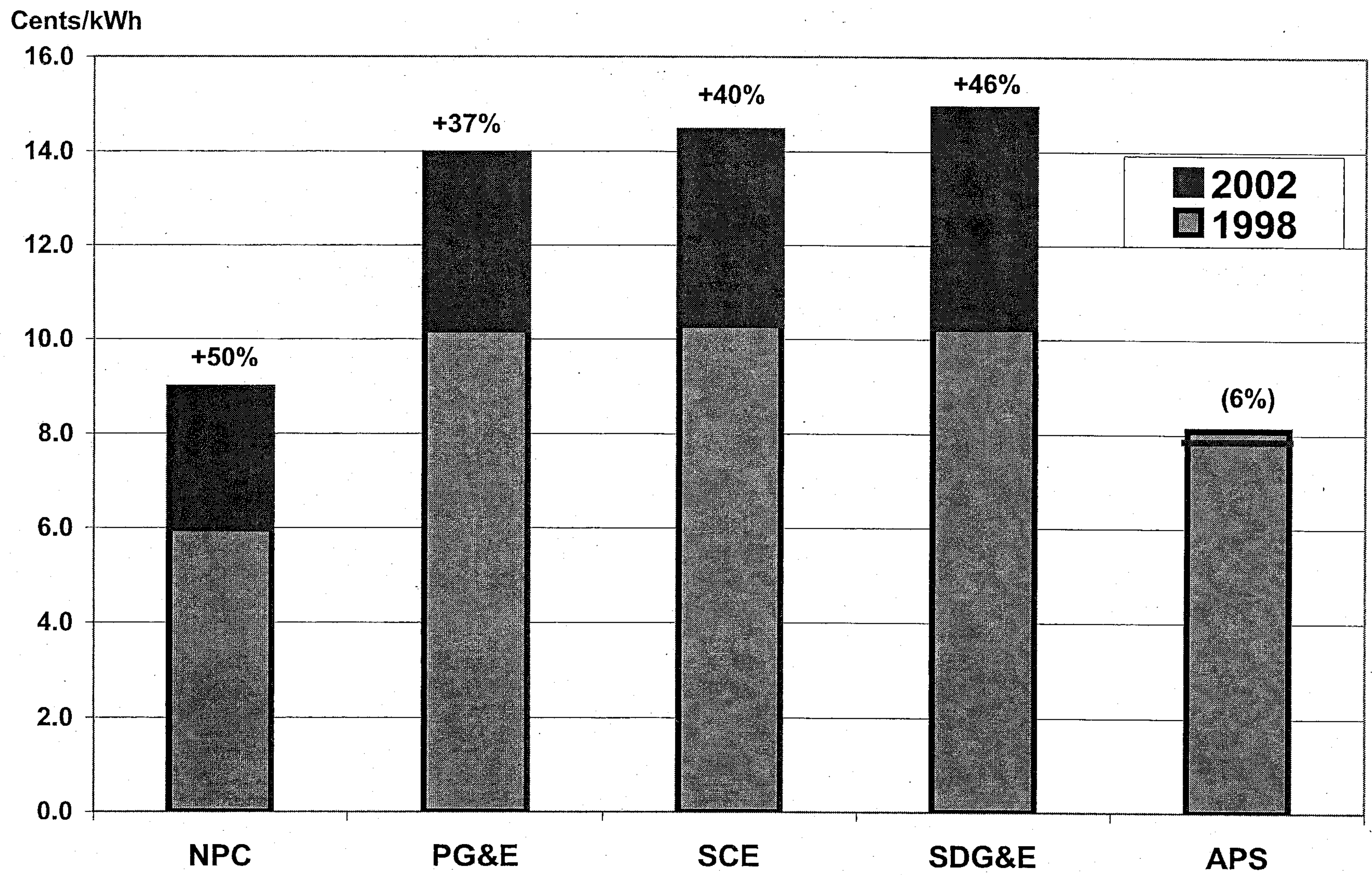
RATIO OF REPORTED CAPACITY TO PEAK LOAD FOR SEVERAL WESTERN U.S INVESTOR-OWNED UTILITIES - SUMMER 2002



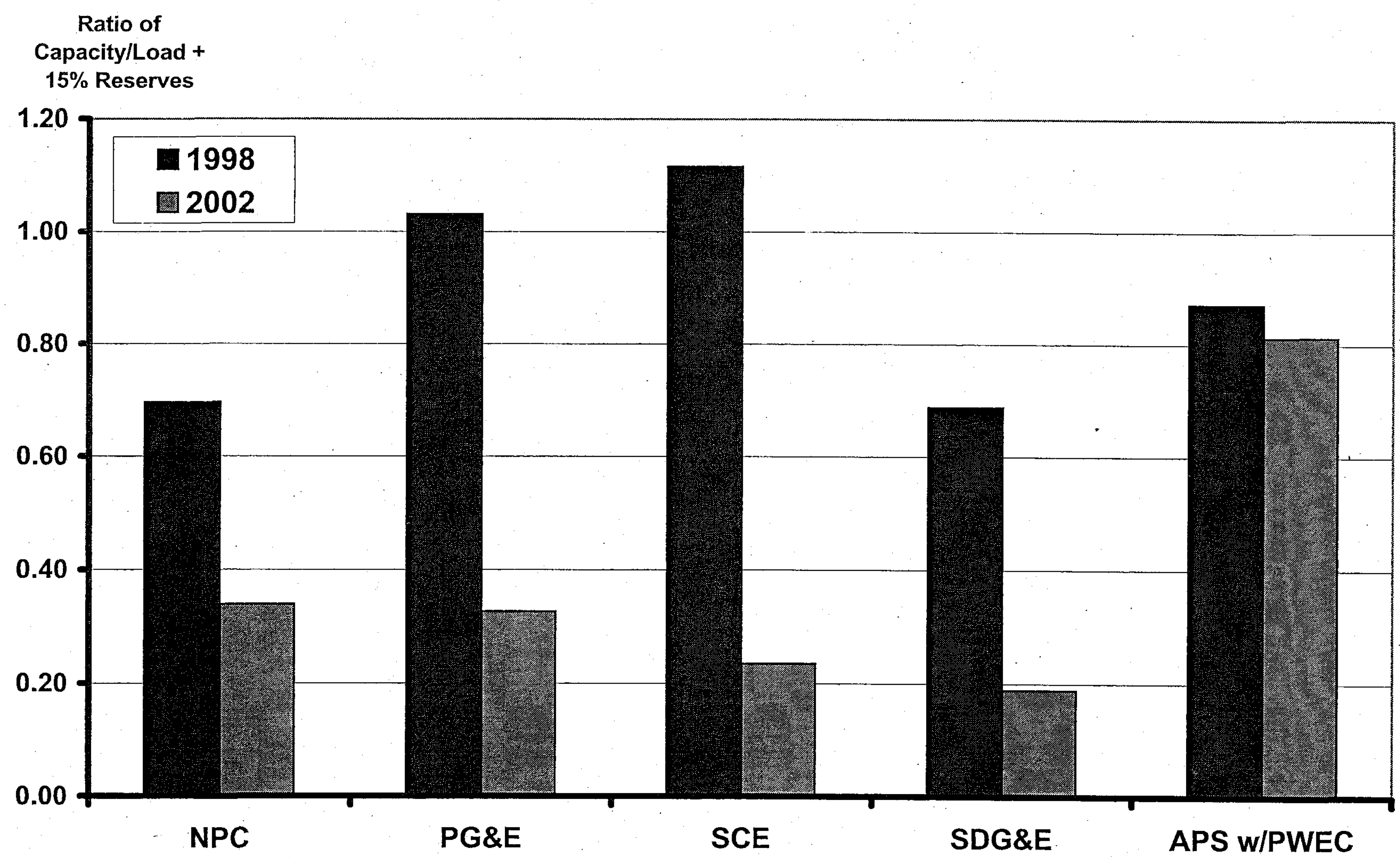
RATIO OF REPORTED CAPACITY TO PEAK LOAD PLUS 15% RESERVES FOR SEVERAL WESTERN U.S INVESTOR-OWNED UTILITIES - SUMMER 2002



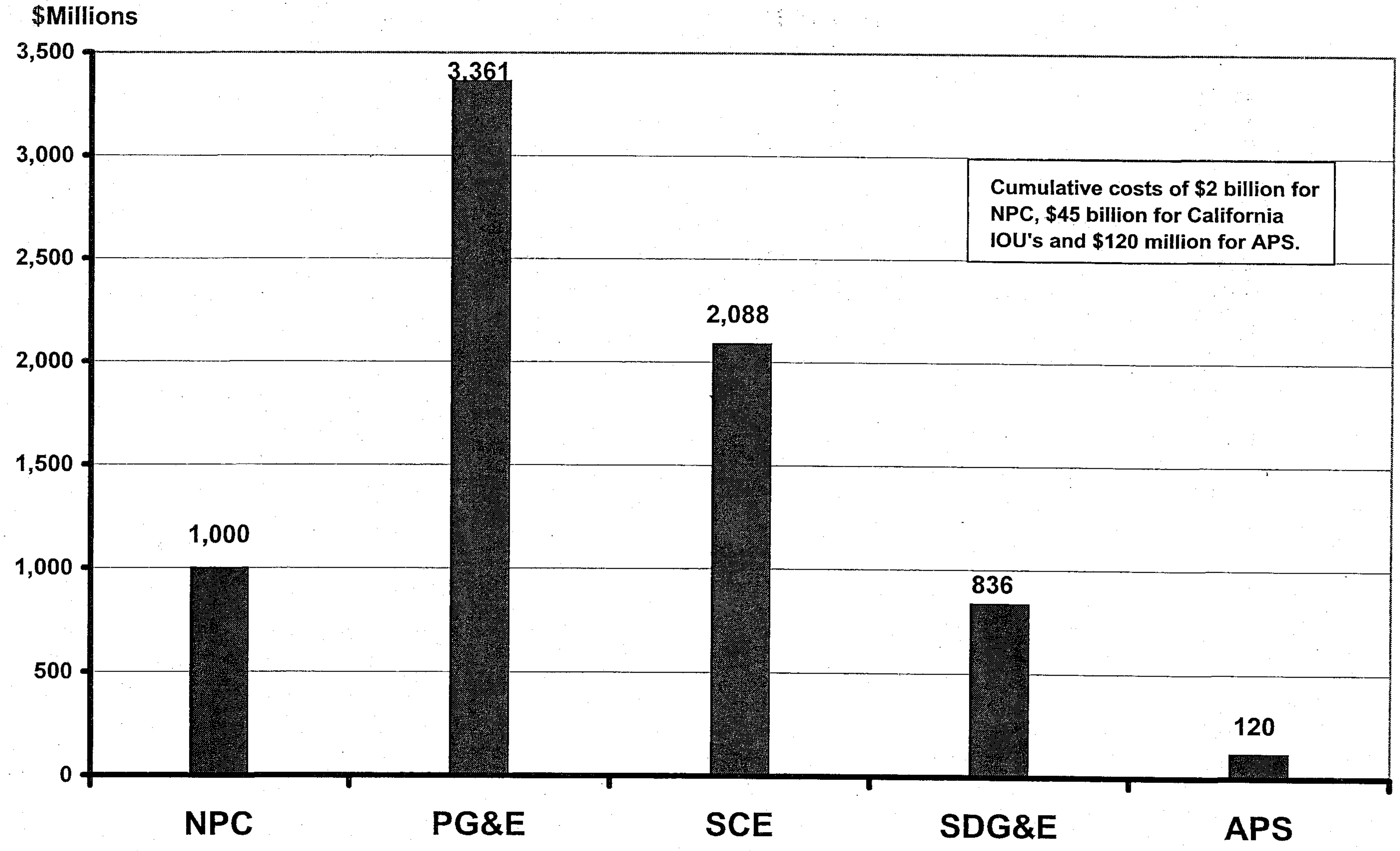
MANAGEMENT OF AVERAGE RETAIL PRICES



UTILITY-OWNED GENERATION CAPACITY & RETAIL PEAK LOAD INCLUDING 15% RESERVES



MANAGEMENT OF MARKET EXPOSURE - 2001

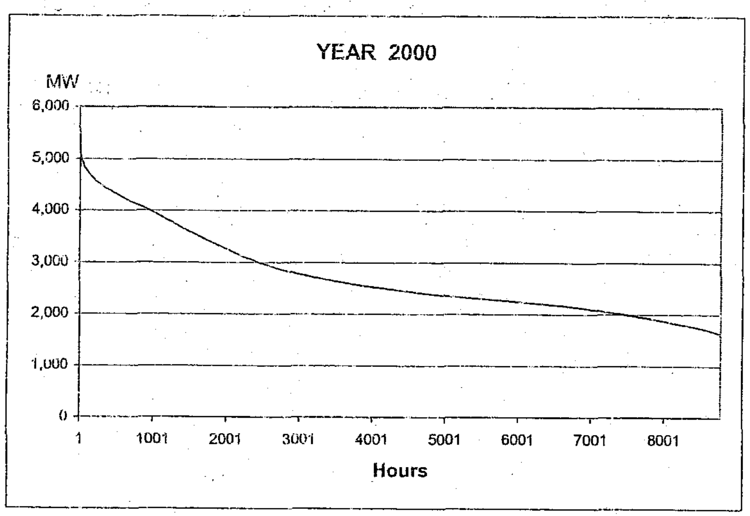


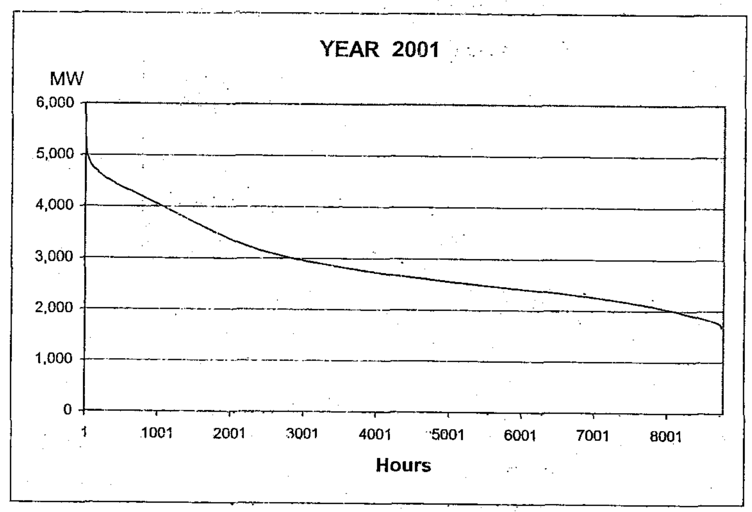
Schedule AB-15RB

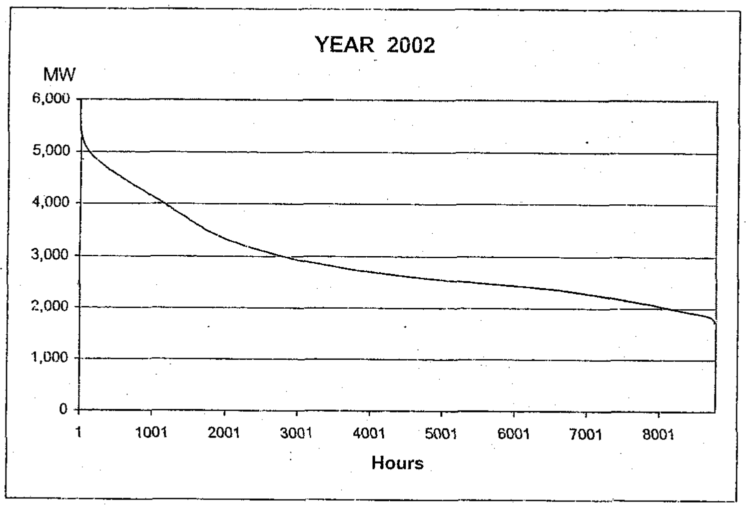
APS and PWEC Power Plants and Expected Duty Cycles

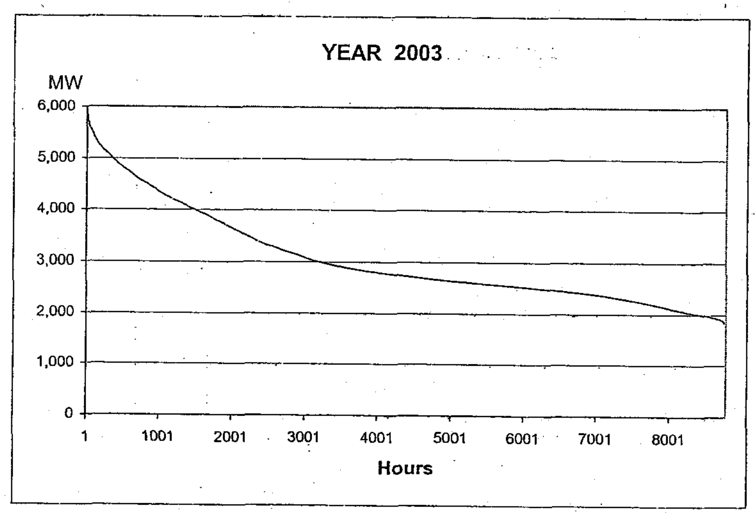
	Capacity - MW		Sub-Total	Expected Duty Cycle
	Summer	Annual		
APS-Owned Power Plants				
Palo Verde 1-3	1113	1113		Baseload
Four Corners 4-5	222	222		Baseload
Navajo	315	315		Baseload
Four Corners 1-3	560	560		Baseload
Cholla 1-3	615	615	2825	Baseload
West Phoenix CC 1-3	240	255	255	Intermediate
Ocotillo Steam 1-2	220	220		Peaking
Saguaro Steam 1-2	210	210		Peaking
Ocotillo CT 1-2	100	110		Peaking
Saguaro CT 1-2	100	110		Peaking
West Phoenix CT 1-2	100	110		Peaking
Yucca CT 1-4	139	147		Peaking
Douglas CT	15	16	923	Peaking
Subtotal APS	3949	4003	4003	
PWEC-Owned Power Plants				
Redhawk CC 1-2	990	990		Baseload
West Phoenix CC5	524	524	1514	Baseload
West Phoenix CC4	110	110	110	Intermediate
Saguaro CT3	76	76	76	Peaking
Subtotal PWEC	1700	1700	1700	

APS Historic Year Load Duration Curve









APS/PWEC Units Operated to Meet Baseload (MW)
Historic 2000-2003 Operation

	2000	2001	2002	2003
Summer				
Palo Verde 1-3	1,113	1,113	1,113	1,113
Four Corners 4-5	222	222	222	222
Navajo 1-3	315	315	315	315
Four Corners 1-3	560	560	560	560
Cholla 1-3	615	615	615	615
West Phoenix CC 1-3	240	240	240	
Ocotillo Steam 1-2	220	220		
Saguaro Steam 1-2	210	210		
Ocotillo CT 1-2				
Saguaro CT 1-2				
West Phoenix CT 1-2				
Yucca CT 1-4				
Douglas CT				
West Phoenix CC 4		110	110	110
West Phoenix CC 5				524
Redhawk CC 1-2			990	990
Saguaro CT3				
Total	3,495	3,605	4,165	4,449
Annual				
Palo Verde 1-3	1,113	1,113	1,113	1,113
Four Corners 4-5	222	222	222	222
Navajo 1-3	315	315	315	315
Four Corners 1-3	560	560	560	560
Cholla 1-3	615	615	615	615
West Phoenix CC 1-3		255		
Ocotillo Steam 1-2				
Saguaro Steam 1-2				
Ocotillo CT 1-2				
Saguaro CT 1-2				
West Phoenix CT 1-2				
Yucca CT 1-4				
Douglas CT				
West Phoenix CC 4		110		
West Phoenix CC 5				
Redhawk CC 1-2			990	
Saguaro CT3				
Total	2,825	3,190	3,815	2,825

HISTORIC CAPACITY FACTORS

YEAR 2000	January	February	March	April	May	June	July	August	September	October	November	December	Annual
APS-Owned Power Plants													
Palo Verde 1-3	92%	101%	101%	68%	96%	101%	101%	97%	96%	67%	91%	102%	93%
Four Corners 4-5	83%	89%	68%	48%	65%	94%	88%	97%	99%	94%	91%	84%	83%
Navajo	84%	65%	80%	78%	83%	85%	83%	93%	84%	86%	95%	94%	84%
Four Corners 1-3	86%	76%	82%	92%	88%	98%	80%	90%	94%	76%	53%	80%	83%
Cholla 1-3	90%	64%	50%	75%	88%	90%	85%	88%	90%	89%	87%	97%	83%
West Phoenix CC 1-3	35%	33%	31%	21%	43%	46%	64%	77%	59%	56%	51%	56%	48%
Ocotillo Steam 1-2	13%	14%	16%	13%	25%	37%	53%	51%	40%	35%	54%	55%	34%
Saguaro Steam 1-2	16%	12%	6%	18%	18%	33%	43%	51%	31%	26%	41%	49%	29%
Ocotillo CT 1-2	1%	1%	0%	2%	10%	20%	23%	34%	22%	10%	0%	0%	10%
Saguaro CT 1-2	2%	1%	2%	2%	6%	14%	22%	31%	22%	10%	24%	32%	14%
West Phoenix CT 1-2	2%	1%	1%	3%	10%	21%	26%	36%	22%	13%	28%	30%	16%
Yucca CT 1-4	1%	0%	1%	5%	4%	6%	9%	18%	11%	5%	11%	22%	8%
Douglas CT	0%	0%	0%	0%	1%	5%	2%	8%	5%	0%	1%	18%	3%
Subtotal APS	66%	62%	60%	55%	68%	76%	75%	79%	75%	63%	69%	78%	69%
PWEC-Owned Power Plants													
Redhawk CC 1-2													
West Phoenix CC4													
West Phoenix CC5													
Saguaro CT3													
Total PWEC													

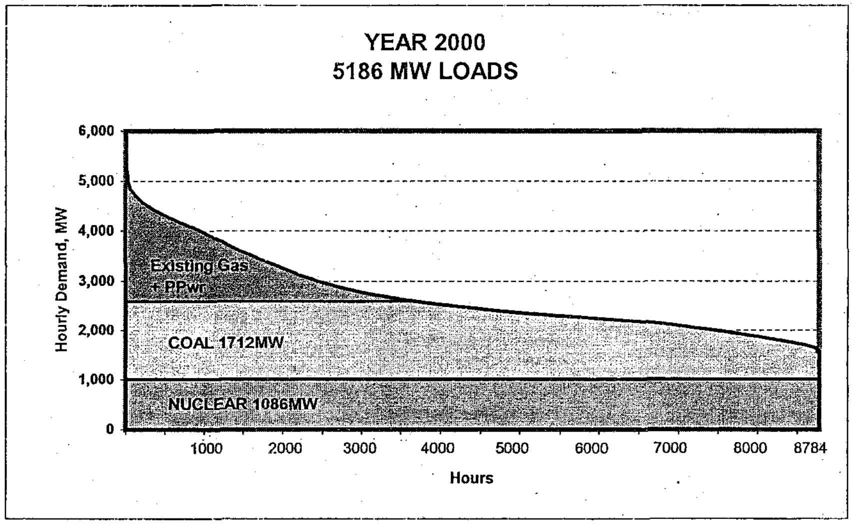
YEAR 2001	January	February	March	April	May	June	July	August	September	October	November	December	Annual
APS-Owned Power Plants													
Palo Verde 1-3	102%	87%	99%	68%	82%	101%	97%	96%	97%	43%	84%	100%	88%
Four Corners 4-5	81%	93%	71%	82%	97%	91%	99%	95%	83%	81%	86%	82%	87%
Navajo	84%	71%	60%	97%	97%	86%	94%	94%	80%	95%	80%	77%	85%
Four Corners 1-3	90%	90%	49%	59%	91%	95%	95%	90%	92%	85%	95%	92%	85%
Cholla 1-3	89%	69%	90%	97%	84%	79%	66%	77%	80%	87%	79%	76%	81%
West Phoenix CC 1-3	62%	57%	49%	43%	59%	53%	59%	56%	52%	50%	28%	41%	51%
Ocotillo Steam 1-2	53%	55%	11%	68%	55%	60%	58%	37%	26%	29%	16%	17%	40%
Saguaro Steam 1-2	20%	63%	49%	47%	76%	45%	60%	49%	18%	20%	10%	4%	38%
Ocotillo CT 1-2	13%	48%	47%	49%	48%	22%	15%	12%	12%	7%	3%	3%	23%
Saguaro CT 1-2	37%	42%	16%	5%	43%	18%	9%	13%	12%	11%	5%	5%	18%
West Phoenix CT 1-2	14%	11%	47%	45%	33%	19%	13%	13%	13%	11%	3%	3%	19%
Yucca CT 1-4	21%	28%	26%	30%	34%	14%	19%	25%	16%	7%	1%	2%	18%
Douglas CT	34%	48%	31%	27%	26%	7%	2%	1%	0%	0%	0%	1%	15%
Subtotal APS	76%	72%	67%	67%	77%	76%	75%	74%	70%	56%	63%	67%	70%
PWEC-Owned Power Plants													
Redhawk CC 1-2													
West Phoenix CC4						90%	90%	89%	85%	56%	50%	72%	76%
West Phoenix CC5													
Saguaro CT3													
Total PWEC						90%	90%	89%	85%	56%	50%	72%	76%

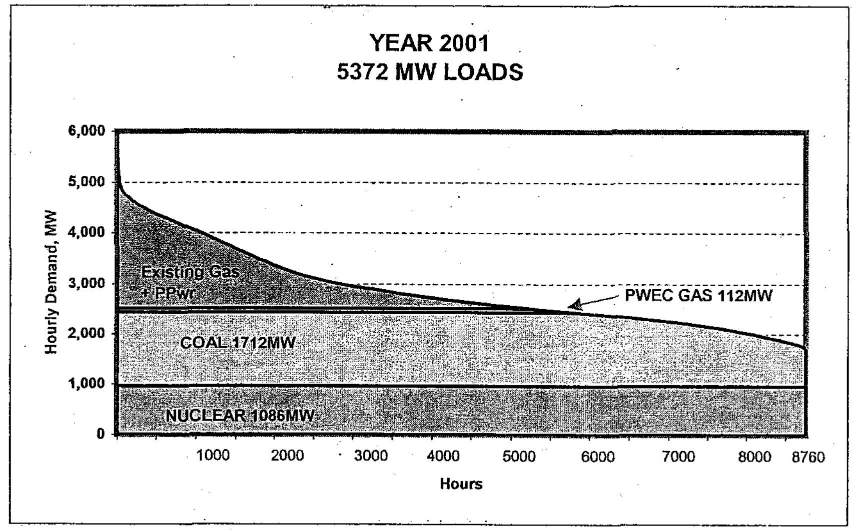
HISTORIC CAPACITY FACTORS

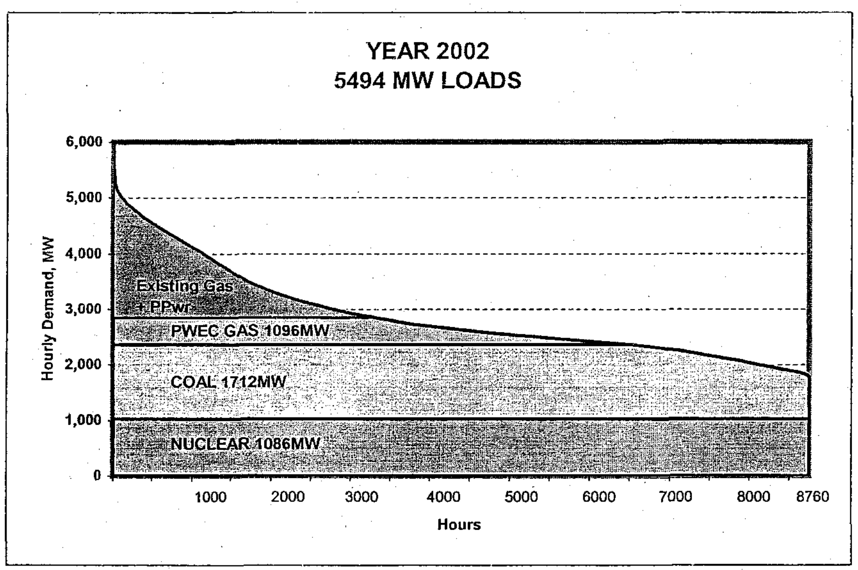
YEAR 2002	January	February	March	April	May	June	July	August	September	October	November	December	Annual
APS-Owned Power Plants													
Palo Verde 1-3	102%	102%	84%	81%	102%	101%	101%	101%	97%	68%	93%	101%	94%
Four Corners 4-5	55%	43%	49%	68%	89%	98%	86%	84%	88%	91%	97%	54%	75%
Navajo	75%	55%	90%	75%	75%	75%	86%	85%	83%	86%	89%	90%	80%
Four Corners 1-3	77%	94%	96%	77%	67%	92%	91%	90%	95%	93%	77%	80%	86%
Cholla 1-3	78%	82%	83%	54%	52%	77%	80%	84%	87%	84%	82%	87%	77%
West Phoenix CC 1-3	34%	24%	32%	39%	46%	47%	58%	57%	42%	31%	27%	26%	39%
Ocotillo Steam 1-2	12%	6%	9%	8%	10%	23%	33%	30%	24%	3%	2%	3%	14%
Saguaro Steam 1-2	2%	3%	1%	5%	11%	21%	30%	28%	23%	2%	0%	0%	11%
Ocotillo CT 1-2	2%	1%	0%	3%	3%	7%	7%	7%	8%	1%	0%	1%	3%
Saguaro CT 1-2	2%	1%	1%	1%	3%	5%	6%	6%	4%	0%	0%	0%	2%
West Phoenix CT 1-2	1%	1%	0%	7%	5%	7%	5%	6%	6%	0%	0%	0%	3%
Yucca CT 1-4	5%	5%	3%	4%	3%	12%	14%	18%	13%	2%	1%	0%	7%
Douglas CT	0%	0%	0%	1%	0%	0%	0%	0%	0%	7%	0%	0%	1%
Subtotal APS	63%	63%	62%	55%	60%	70%	72%	72%	71%	59%	63%	64%	65%
PWEC-Owned Power Plants													
Redhawk CC 1-2								62%	48%	48%	52%	62%	54%
West Phoenix CC4	24%	18%	67%	56%	47%	65%	68%	66%	53%	38%	37%	35%	48%
West Phoenix CC5													
Saguaro CT3							25%	18%	22%	3%	2%	3%	12%
Total PWEC	24%	18%	67%	56%	47%	65%	50%	59%	47%	44%	47%	56%	50%

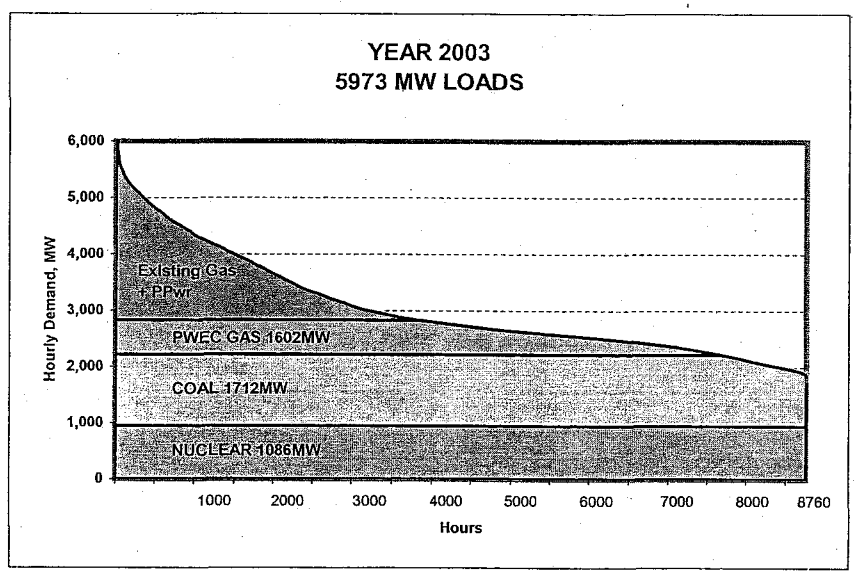
YEAR 2003	January	February	March	April	May	June	July	August	September	October	November	December	Annual
APS-Owned Power Plants													
Palo Verde 1-3	102%	102%	92%	67%	99%	93%	93%	90%	96%	67%	67%	83%	87%
Four Corners 4-5	94%	89%	102%	101%	91%	91%	93%	97%	70%	92%	69%	90%	90%
Navajo	78%	67%	53%	58%	69%	83%	93%	90%	88%	65%	78%	75%	75%
Four Corners 1-3	75%	88%	75%	53%	80%	92%	95%	78%	78%	90%	92%	94%	82%
Cholla 1-3	84%	70%	52%	60%	75%	81%	92%	54%	50%	46%	48%	69%	65%
West Phoenix CC 1-3	24%	15%	28%	37%	32%	30%	46%	38%	33%	31%	28%	26%	31%
Ocotillo Steam 1-2	0%	0%	1%	1%	12%	8%	25%	21%	15%	5%	8%	12%	9%
Saguaro Steam 1-2	0%	0%	0%	0%	9%	4%	18%	12%	5%	7%	2%	8%	6%
Ocotillo CT 1-2	0%	1%	1%	0%	4%	0%	2%	2%	0%	4%	0%	0%	1%
Saguaro CT 1-2	0%	1%	0%	0%	3%	0%	3%	2%	1%	2%	0%	1%	1%
West Phoenix CT 1-2	0%	0%	0%	0%	3%	0%	2%	2%	1%	1%	0%	0%	1%
Yucca CT 1-4	0%	1%	2%	0%	5%	1%	5%	7%	14%	3%	0%	0%	3%
Douglas CT	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%
Subtotal APS	64%	62%	56%	48%	64%	65%	71%	61%	59%	51%	51%	60%	59%
PWEC-Owned Power Plants													
Redhawk CC 1-2	27%	67%	55%	58%	36%	60%	78%	64%	66%	4%	2%	0%	43%
West Phoenix CC4	18%	39%	62%	68%	34%	45%	85%	64%	52%	17%	1%	0%	40%
West Phoenix CC5								68%	67%	58%	2%	0%	39%
Saguaro CT3	1%	3%	3%	2%	11%	1%	8%	9%	4%	1%	1%	0%	4%
Total PWEC	24%	60%	52%	56%	34%	55%	74%	62%	62%	21%	2%	0%	40%

APS Historic Year Load Duration Curves With Actual Plant Types to Meet Load









APS/PWEC Units Operated to Meet Baseload (MW)
Projected 2000-2003 Operation

	2000	2001	2002	2003
Summer				
Palo Verde 1-3	1,113	1,113	1,113	1,113
Four Corners 4-5	222	222	222	222
Navajo 1-3	315	315	315	315
Four Corners 1-3	560	560	560	560
Cholla 1-3	615	615	615	615
West Phoenix CC 1-3	240	240	240	240
Ocotillo Steam 1-2	220	220	220	220
Saguaro Steam 1-2				
Ocotillo CT 1-2				
Saguaro CT 1-2				
West Phoenix CT 1-2				
Yucca CT 1-4				
Douglas CT				
West Phoenix CC 4		110	110	
West Phoenix CC 5				524
Redhawk CC 1-2			990	990
Saguaro CT3				
Total	3,285	3,395	4,385	4,799
Annual				
Palo Verde 1-3	1,113	1,113	1,113	1,113
Four Corners 4-5	222	222	222	222
Navajo 1-3	315	315	315	315
Four Corners 1-3	560	560	560	560
Cholla 1-3	615	615	615	615
West Phoenix CC 1-3		255	255	
Ocotillo Steam 1-2				
Saguaro Steam 1-2				
Ocotillo CT 1-2				
Saguaro CT 1-2				
West Phoenix CT 1-2				
Yucca CT 1-4				
Douglas CT				
West Phoenix CC 4		110		
West Phoenix CC 5				524
Redhawk CC 1-2			990	
Saguaro CT3				
Total	2,825	3,190	4,070	3,349

PROJECTED POWER PLANT CAPACITY FACTORS

YEAR 2000[1]	January	February	March	April	May	June	July	August	September	October	November	December	Annual
APS-Owned Power Plants													
Palo Verde 1-3	98%	98%	97%	67%	86%	98%	97%	97%	95%	66%	89%	99%	**91%**
Four Corners 4-5	92%	93%	65%	45%	76%	92%	92%	93%	92%	92%	92%	92%	**85%**
Navajo	71%	53%	78%	76%	74%	70%	81%	84%	87%	82%	72%	79%	**76%**
Four Corners 1-3	88%	84%	89%	90%	80%	88%	90%	90%	90%	69%	68%	87%	**84%**
Cholla 1-3	83%	75%	52%	85%	82%	77%	87%	89%	92%	92%	83%	80%	**81%**
West Phoenix CC 1-3	42%	32%	24%	37%	52%	61%	70%	72%	64%	58%	35%	45%	**49%**
Ocotillo Steam 1-2	7%	5%	2%	5%	21%	36%	45%	53%	38%	36%	17%	20%	**23%**
Saguaro Steam 1-2	4%	1%	0%	5%	3%	17%	18%	30%	15%	14%	4%	10%	**10%**
Ocotillo CT 1-2	0%	0%	0%	0%	0%	7%	5%	13%	3%	2%	0%	1%	**3%**
Saguaro CT 1-2	1%	0%	0%	0%	0%	6%	3%	8%	1%	4%	0%	2%	**2%**
West Phoenix CT 1-2	1%	1%	0%	1%	1%	11%	5%	12%	3%	1%	0%	0%	**3%**
Yucca CT 1-4	1%	1%	0%	1%	1%	6%	4%	10%	3%	4%	1%	3%	**3%**
Douglas CT	0%	0%	0%	0%	0%	0%	1%	3%	0%	0%	0%	0%	**0%**
PWEC Owned Power Plants													
Redhawk CC 1-2													
West Phoenix CC4													
West Phoenix CC5													
Saguaro CT3													

YEAR 2001[2]	January	February	March	April	May	June	July	August	September	October	November	December	Annual
APS-Owned Power Plants													
Palo Verde 1-3	99%	99%	98%	66%	92%	98%	97%	97%	96%	66%	95%	99%	**92%**
Four Corners 4-5	93%	92%	92%	92%	83%	92%	92%	93%	92%	92%	86%	93%	**91%**
Navajo	78%	67%	66%	90%	89%	93%	94%	95%	95%	94%	88%	90%	**87%**
Four Corners 1-3	92%	82%	66%	88%	92%	91%	91%	93%	92%	92%	92%	91%	**89%**
Cholla 1-3	82%	76%	80%	62%	84%	91%	93%	95%	95%	85%	81%	82%	**84%**
West Phoenix CC 1-3	73%	59%	36%	46%	50%	78%	87%	98%	96%	76%	50%	63%	**68%**
Ocotillo Steam 1-2	34%	30%	0%	27%	31%	43%	57%	68%	65%	48%	30%	17%	**38%**
Saguaro Steam 1-2	7%	9%	15%	11%	15%	19%	33%	38%	37%	26%	9%	15%	**20%**
Ocotillo CT 1-2	14%	13%	4%	7%	11%	18%	30%	37%	34%	14%	5%	7%	**16%**
Saguaro CT 1-2	12%	8%	1%	0%	8%	14%	26%	34%	29%	18%	3%	7%	**13%**
West Phoenix CT 1-2	4%	0%	8%	14%	16%	25%	34%	41%	38%	25%	12%	14%	**19%**
Yucca CT 1-4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
Douglas CT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
PWEC Owned Power Plants													
Redhawk CC 1-2													
West Phoenix CC4					28%	67%	81%	85%	84%	70%	47%	60%	**65%**
West Phoenix CC5													
Saguaro CT3													

Notes: (1) Source for year 2000 capacity factor projection is APS 2000 Budget Forecast prepared 12/1999.
(2) Source for year 2001-2003 capacity factor projection is APS 2001 Budget Forecast prepared 12/2000.

PROJECTED POWER PLANT CAPACITY FACTORS

YEAR 2002[2]	January	February	March	April	May	June	July	August	September	October	November	December	Annual
APS-Owned Power Plants													
Palo Verde 1-3	99%	99%	97%	66%	93%	98%	98%	97%	94%	66%	95%	99%	**92%**
Four Corners 4-5	86%	46%	51%	94%	91%	92%	93%	92%	91%	93%	93%	91%	**85%**
Navajo	93%	66%	89%	93%	90%	89%	92%	94%	94%	90%	87%	90%	**89%**
Four Corners 1-3	83%	92%	92%	82%	63%	90%	92%	90%	92%	92%	92%	91%	**88%**
Cholla 1-3	84%	78%	47%	61%	85%	84%	90%	94%	93%	82%	76%	79%	**79%**
West Phoenix CC 1-3	62%	45%	41%	52%	39%	52%	69%	88%	81%	41%	42%	53%	**56%**
Ocotillo Steam 1-2	11%	8%	1%	17%	28%	23%	43%	58%	52%	24%	2%	12%	**23%**
Saguaro Steam 1-2	9%	6%	4%	7%	13%	11%	25%	32%	29%	10%	0%	2%	**12%**
Ocotillo CT 1-2	1%	1%	0%	1%	6%	9%	20%	30%	26%	3%	0%	1%	**8%**
Saguaro CT 1-2	1%	1%	1%	4%	9%	7%	17%	26%	21%	5%	0%	0%	**8%**
West Phoenix CT 1-2	5%	2%	4%	5%	13%	12%	24%	35%	31%	8%	2%	2%	**12%**
Yucca CT 1-4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
Douglas CT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
PWEC Owned Power Plants													
Redhawk CC 1-2						76%	86%	92%	91%	58%	26%	30%	**66%**
West Phoenix CC4	40%	25%	23%	41%	41%	43%	62%	78%	75%	12%	0%	0%	**37%**
West Phoenix CC5													
Saguaro CT3													

YEAR 2003[2]	January	February	March	April	May	June	July	August	September	October	November	December	Annual
APS-Owned Power Plants													
Palo Verde 1-3	99%	99%	96%	66%	94%	99%	98%	97%	93%	66%	66%	86%	**88%**
Four Corners 4-5	91%	83%	87%	59%	79%	77%	79%	84%	87%	87%	88%	88%	**83%**
Navajo	73%	68%	62%	83%	87%	82%	86%	89%	92%	94%	94%	94%	**84%**
Four Corners 1-3	80%	57%	45%	74%	73%	72%	76%	80%	80%	79%	79%	79%	**73%**
Cholla 1-3	86%	86%	77%	58%	76%	72%	78%	84%	87%	86%	83%	85%	**80%**
West Phoenix CC 1-3	45%	39%	27%	24%	30%	41%	56%	67%	52%	37%	44%	52%	**43%**
Ocotillo Steam 1-2	8%	5%	3%	6%	14%	15%	33%	50%	43%	22%	3%	11%	**18%**
Saguaro Steam 1-2	1%	1%	1%	1%	2%	6%	17%	28%	24%	8%	1%	3%	**8%**
Ocotillo CT 1-2	0%	0%	0%	0%	3%	4%	13%	24%	22%	4%	1%	1%	**6%**
Saguaro CT 1-2	0%	0%	0%	1%	4%	3%	11%	19%	17%	6%	1%	1%	**5%**
West Phoenix CT 1-2	1%	0%	1%	2%	6%	5%	16%	27%	25%	8%	1%	2%	**8%**
Yucca CT 1-4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
Douglas CT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**0%**
PWEC Owned Power Plants													
Redhawk CC 1-2	29%	16%	17%	34%	21%	36%	74%	83%	84%	38%	24%	24%	**40%**
West Phoenix CC4	0%	0%	0%	0%	1%	4%	30%	53%	40%	6%	0%	0%	**11%**
West Phoenix CC5						15%	52%	78%	77%	74%	74%	75%	**64%**
Saguaro CT3													

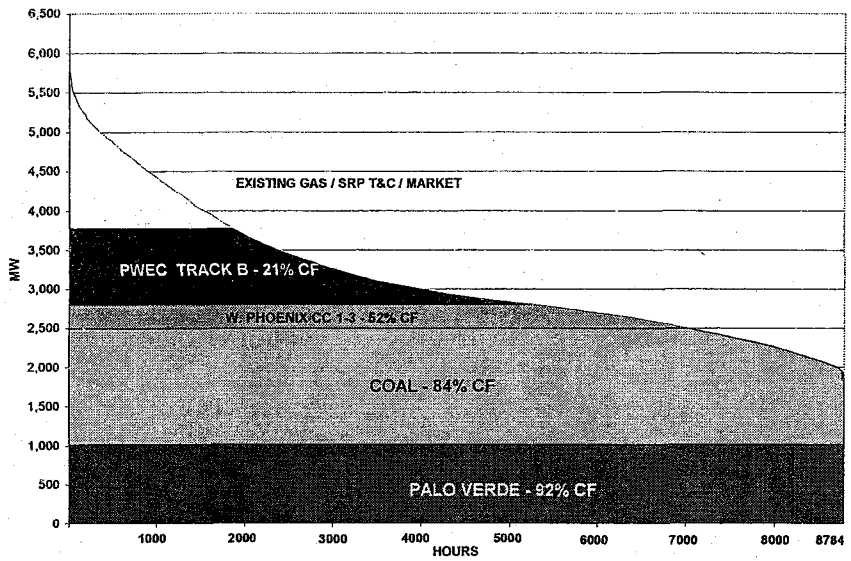
Notes: (1) Source for year 2000 capacity factor projection is APS 2000 Budget Forecast prepared 12/1999.
(2) Source for year 2001-2003 capacity factor projection is APS 2001 Budget Forecast prepared 12/2000.

APS/PWEC Units Operated to Meet Baseload (MW)
Case 1 (PWEC Units Available to APS System)

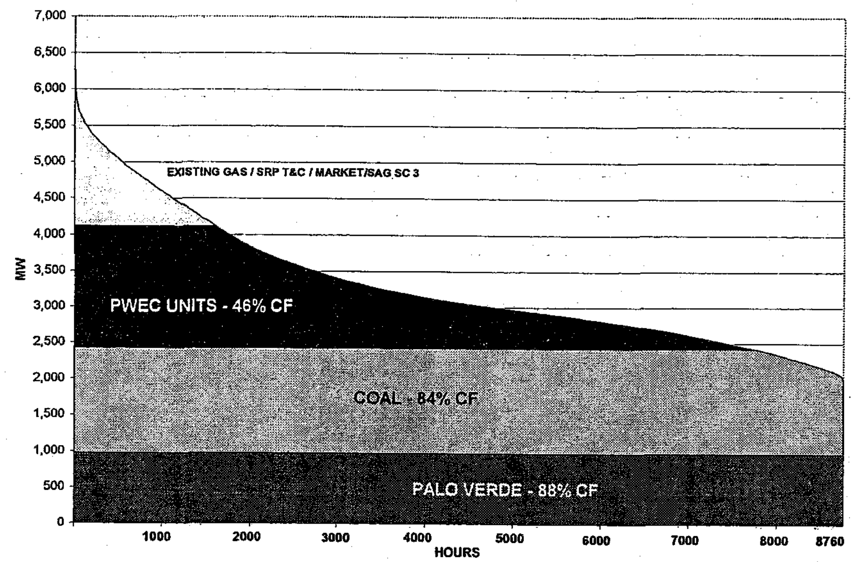
	2004	2005	2006	2007	2008	2009	2010
Summer							
Palo Verde 1-3	1,113	1,113	1,113	1,113	1,113	1,113	1,113
Four Corners 4-5	222	222	222	222	222	222	222
Navajo 1-3	315	315	315	315	315	315	315
Four Corners 1-3	560	560	560	560	560	560	560
Cholla 1-3	615	615	615	615	615	615	615
West Phoenix CC 1-3		240	240	240	240	240	240
Ocotillo Steam 1-2			220		220	220	220
Saguaro Steam 1-2							
Ocotillo CT 1-2							
Saguaro CT 1-2							
West Phoenix CT 1-2							
Yucca CT 1-4							
Douglas CT							
West Phoenix CC 4	110	110	110	110	110	110	110
West Phoenix CC 5	524	524	524	524	524	524	524
Redhawk CC 1-2	990	990	990	990	990	990	990
Saguaro CT3							
Total	4,449	4,689	4,909	4,689	4,909	4,909	4,909
Annual							
Palo Verde 1-3	1,113	1,113	1,113	1,113	1,113	1,113	1,113
Four Corners 4-5	222	222	222	222	222	222	222
Navajo 1-3	315	315	315	315	315	315	315
Four Corners 1-3	560	560	560	560	560	560	560
Cholla 1-3	615	615	615	615	615	615	615
West Phoenix CC 1-3	255						
Ocotillo Steam 1-2							
Saguaro Steam 1-2							
Ocotillo CT 1-2							
Saguaro CT 1-2							
West Phoenix CT 1-2							
Yucca CT 1-4							
Douglas CT							
West Phoenix CC 4							
West Phoenix CC 5		524	524	524	524	524	524
Redhawk CC 1-2					990	990	990
Saguaro CT3							
Total	3,080	3,349	3,349	3,349	4,339	4,339	4,339

APS Load Duration Curve
Case 1 - With PWEC Units Available to APS System

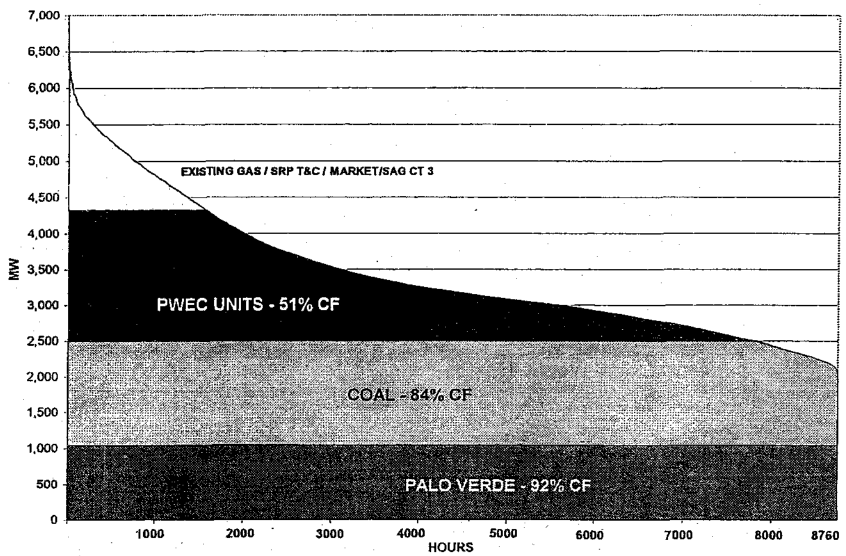
YEAR 2004



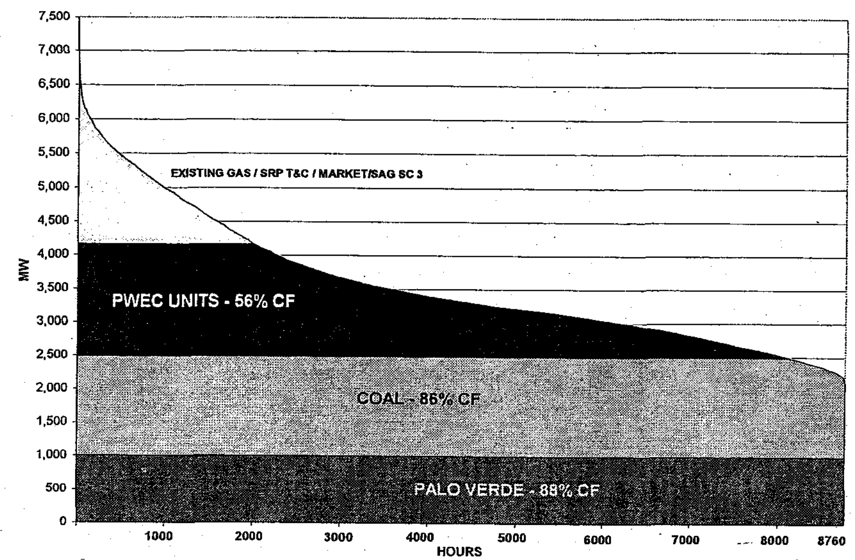
YEAR 2005



YEAR 2006

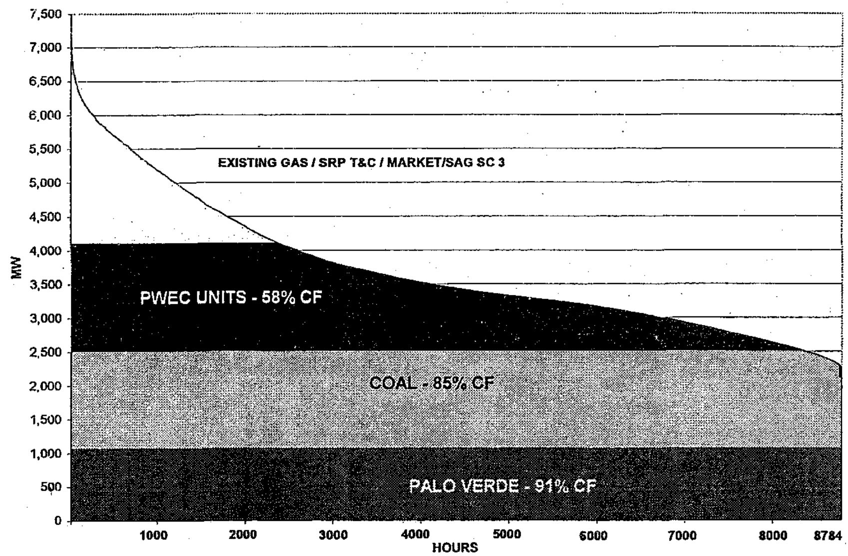


YEAR 2007

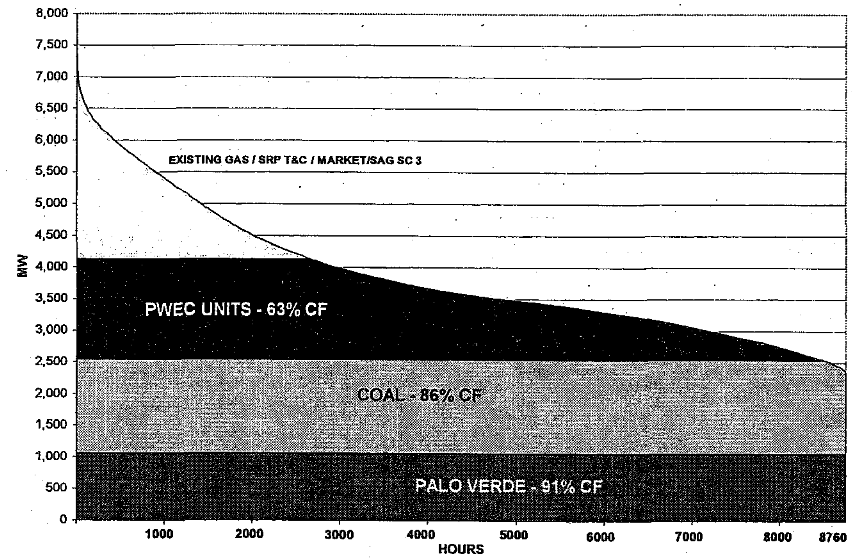


APS Load Duration Curve
Case 1 - With PWEC Units Available to APS System

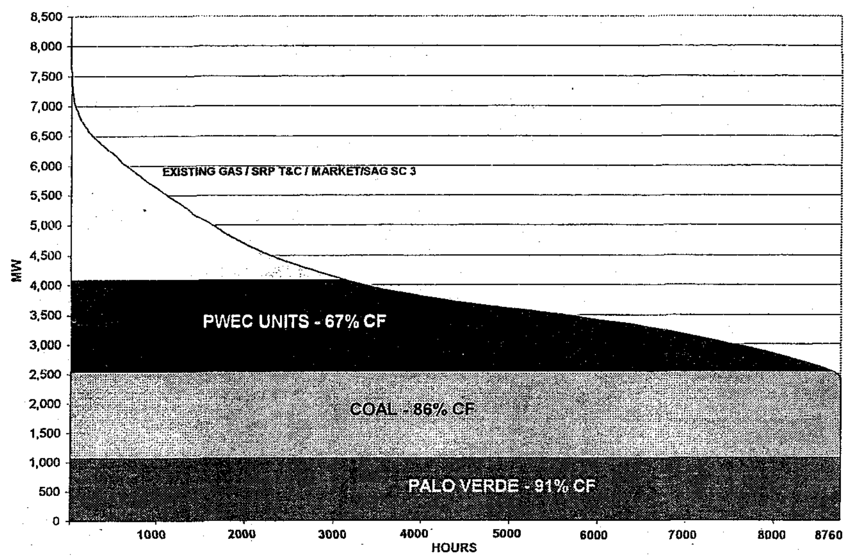
YEAR 2008



YEAR 2009



YEAR 2010



Notes:

(1) Source is 2003 LRF MAPS run.

(2) Does not reflect potential off-system economy purchases or sales. PWEC units may operate more or less than indicated on the load duration curves to benefit from prevailing market conditions.

(3) APS 2003 LRF RTSim includes the following interchange sales (GWH):

2004	2005	2006	2007	2008
1951	2180	2784	2437	2440

(4) PWEC Units include Redhawk CC 1-2, W Phx CC 4-5.

APS Capacity Factors

Case 1 - With PWEC Units Available to APS System

Year - 2004

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	92%	91%	101%	70%	91%	100%	100%	100%	100%	68%	94%	90%	92%
Four Corners 1-2-3	87%	88%	61%	74%	54%	61%	99%	99%	97%	93%	74%	84%	81%
Four Corners 4-5	66%	47%	48%	98%	100%	52%	50%	100%	100%	91%	100%	93%	79%
Navajo 1-2-3	96%	61%	69%	80%	100%	100%	100%	100%	60%	100%	100%	95%	89%
Cholla 1-2-3	83%	76%	83%	95%	86%	69%	99%	98%	95%	90%	68%	79%	85%
Hydro	95%	93%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
W. Phoenix CC 1-3	59%	51%	51%	72%	89%	48%	21%	19%	30%	70%	72%	45%	52%
Ocotillo 1-2	29%	48%	13%	53%	74%	16%	10%	12%	32%	56%	32%	48%	35%
Saguaro 1-2	35%	32%	1%	20%	62%	4%	6%	6%	10%	36%	25%	31%	23%
Yucca CT 1-4	2%	0%	0%	4%	29%	0%	1%	0%	0%	16%	0%	7%	5%
Ocotillo CT 1-2	14%	1%	0%	13%	53%	0%	2%	0%	0%	23%	0%	24%	11%
Saguaro CT 1-2	20%	21%	0%	15%	46%	0%	5%	0%	0%	12%	1%	33%	13%
W. Phoenix CT 1-2	9%	13%	0%	5%	44%	0%	0%	0%	0%	21%	0%	18%	9%
Douglas CT	2%	0%	0%	4%	29%	0%	0%	0%	0%	23%	0%	4%	5%
W. Phoenix CC 4	0%	0%	0%	0%	0%	25%	51%	48%	55%	0%	0%	0%	15%
W. Phoenix CC 5	0%	0%	0%	0%	0%	94%	86%	85%	79%	0%	0%	0%	29%
Redhawk CC 1&2	0%	0%	0%	0%	0%	77%	65%	57%	27%	0%	0%	0%	19%
Saguaro SC 3	0%	0%	0%	0%	0%	0%	5%	0%	4%	0%	0%	0%	1%

Year - 2005

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	100%	91%	101%	67%	92%	100%	90%	100%	100%	58%	68%	86%	88%
Four Corners 1-2-3	87%	71%	25%	100%	39%	100%	100%	99%	99%	99%	100%	89%	84%
Four Corners 4-5	88%	91%	94%	70%	100%	50%	100%	90%	100%	50%	83%	94%	84%
Navajo 1-2-3	69%	60%	91%	76%	63%	100%	100%	100%	100%	100%	100%	96%	88%
Cholla 1-2-3	75%	78%	78%	63%	38%	100%	99%	98%	94%	93%	71%	78%	80%
Hydro	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
W. Phoenix CC 1-3	4%	0%	0%	0%	56%	17%	46%	51%	8%	7%	0%	0%	16%
Ocotillo 1-2	0%	0%	0%	0%	37%	3%	19%	24%	3%	11%	0%	0%	8%
Saguaro 1-2	0%	0%	0%	0%	20%	1%	12%	19%	1%	7%	0%	0%	5%
Yucca CT 1-4	0%	0%	0%	0%	4%	0%	1%	8%	0%	0%	0%	0%	1%
Ocotillo CT 1-2	0%	0%	0%	0%	4%	0%	1%	6%	0%	0%	0%	0%	1%
Saguaro CT 1-2	0%	0%	0%	0%	2%	0%	5%	7%	0%	0%	0%	0%	1%
W. Phoenix CT 1-2	0%	0%	0%	0%	0%	0%	4%	4%	0%	0%	0%	0%	1%
Douglas CT	0%	0%	0%	0%	0%	0%	2%	4%	0%	0%	0%	0%	0%
W. Phoenix CC 4	11%	0%	0%	1%	68%	49%	60%	70%	32%	9%	0%	0%	25%
W. Phoenix CC 5	30%	64%	52%	82%	35%	89%	89%	88%	78%	73%	79%	64%	69%
Redhawk CC 1&2	25%	11%	7%	26%	89%	67%	72%	51%	49%	35%	19%	18%	39%
Saguaro SC 3	0%	0%	0%	0%	9%	0%	0%	15%	0%	3%	0%	0%	2%

APS Capacity Factors

Case 1 - With PWEC Units Available to APS System

Year - 2006

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	101%	81%	101%	69%	94%	91%	100%	100%	99%	66%	96%	101%	92%
Four Corners 1-2-3	87%	33%	62%	100%	100%	100%	100%	100%	99%	95%	23%	83%	82%
Four Corners 4-5	47%	95%	96%	100%	97%	100%	93%	50%	100%	93%	92%	90%	88%
Navajo 1-2-3	75%	97%	70%	98%	100%	100%	58%	100%	100%	100%	100%	91%	91%
Cholla 1-2-3	73%	64%	70%	53%	70%	99%	99%	98%	96%	85%	99%	68%	81%
Hydro	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
W. Phoenix CC 1-3	0%	8%	0%	0%	5%	32%	54%	48%	17%	13%	0%	0%	15%
Ocotillo 1-2	0%	1%	0%	0%	1%	10%	50%	29%	7%	9%	0%	0%	9%
Saguaro 1-2	0%	0%	0%	0%	0%	7%	28%	20%	7%	8%	0%	0%	6%
Yucca CT 1-4	0%	0%	0%	0%	0%	0%	9%	6%	0%	0%	0%	0%	1%
Ocotillo CT 1-2	0%	0%	0%	0%	0%	0%	0%	5%	0%	0%	0%	0%	0%
Saguaro CT 1-2	0%	0%	0%	0%	0%	0%	12%	9%	0%	2%	0%	0%	2%
W. Phoenix CT 1-2	0%	0%	0%	0%	0%	0%	8%	5%	0%	0%	0%	0%	1%
Douglas CT	0%	0%	0%	0%	0%	0%	8%	5%	0%	0%	0%	0%	1%
Future CTs													
W. Phoenix CC 4	0%	11%	0%	3%	25%	56%	63%	58%	42%	17%	0%	2%	23%
W. Phoenix CC 5	70%	79%	44%	73%	77%	85%	91%	90%	82%	31%	68%	40%	69%
Redhawk CC 1&2	25%	36%	9%	33%	47%	76%	76%	73%	57%	51%	26%	35%	45%
Saguaro SC 3	0%	0%	0%	0%	0%	1%	0%	15%	1%	5%	0%	0%	2%

Year - 2007

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	92%	100%	100%	59%	94%	90%	100%	100%	98%	68%	69%	89%	88%
Four Corners 1-2-3	91%	45%	78%	100%	100%	77%	98%	100%	100%	98%	53%	82%	85%
Four Corners 4-5	95%	91%	98%	87%	76%	50%	50%	100%	100%	100%	100%	96%	87%
Navajo 1-2-3	96%	90%	69%	99%	100%	80%	78%	100%	80%	100%	100%	99%	91%
Cholla 1-2-3	82%	82%	74%	83%	94%	100%	69%	87%	98%	89%	74%	83%	85%
Hydro	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
W. Phoenix CC 1-3	11%	1%	0%	0%	9%	34%	67%	49%	31%	6%	0%	21%	19%
Ocotillo 1-2	7%	0%	0%	0%	1%	21%	48%	22%	33%	5%	0%	7%	12%
Saguaro 1-2	2%	0%	0%	0%	0%	6%	14%	9%	0%	0%	0%	0%	3%
Yucca CT 1-4	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	0%
Ocotillo CT 1-2	0%	0%	0%	0%	0%	0%	5%	0%	0%	0%	0%	0%	0%
Saguaro CT 1-2	0%	0%	0%	0%	0%	0%	6%	0%	0%	0%	0%	0%	1%
W. Phoenix CT 1-2	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%	0%
Douglas CT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Future CTs	0%	0%	0%	0%	0%	42%	45%	19%	4%	1%	0%	0%	9%
W. Phoenix CC 4	21%	11%	0%	6%	33%	31%	76%	59%	51%	14%	4%	32%	28%
W. Phoenix CC 5	42%	71%	19%	80%	75%	97%	96%	90%	87%	70%	94%	71%	74%
Redhawk CC 1&2	29%	16%	22%	39%	52%	88%	87%	75%	66%	33%	52%	23%	49%
Saguaro SC 3	0%	0%	0%	0%	0%	2%	9%	4%	0%	0%	0%	0%	1%

APS Capacity Factors

Case 1 - With PWEC Units Available to APS System

Year - 2008

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	101%	98%	89%	67%	97%	100%	100%	100%	100%	61%	92%	91%	91%
Four Corners 1-2-3	70%	83%	95%	95%	71%	100%	61%	100%	68%	99%	89%	84%	85%
Four Corners 4-5	75%	44%	49%	92%	97%	50%	100%	100%	100%	84%	99%	58%	79%
Navajo 1-2-3	95%	85%	69%	100%	62%	100%	100%	100%	100%	76%	99%	99%	90%
Cholla 1-2-3	83%	53%	74%	96%	99%	70%	100%	97%	87%	68%	86%	86%	83%
Hydro	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
W. Phoenix CC 1-3	2%	0%	0%	0%	37%	34%	68%	49%	42%	17%	0%	32%	24%
Ocotillo 1-2	0%	0%	0%	0%	14%	52%	43%	22%	19%	3%	0%	18%	14%
Saguaro 1-2	0%	0%	0%	0%	0%	9%	13%	5%	12%	0%	0%	0%	3%
Yucca CT 1-4	0%	0%	0%	0%	0%	0%	3%	0%	1%	0%	0%	0%	0%
Ocotillo CT 1-2	0%	0%	0%	0%	0%	0%	3%	0%	1%	0%	0%	0%	0%
Saguaro CT 1-2	0%	0%	0%	0%	0%	1%	6%	0%	1%	0%	0%	0%	1%
W. Phoenix CT 1-2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Douglas CT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Future CTs	0%	0%	0%	0%	3%	47%	45%	18%	36%	3%	0%	3%	13%
W. Phoenix CC 4	10%	2%	0%	2%	47%	83%	76%	60%	70%	35%	59%	40%	40%
W. Phoenix CC 5	72%	68%	72%	81%	87%	97%	96%	90%	43%	78%	7%	44%	70%
Redhawk CC 1&2	32%	36%	19%	38%	66%	65%	88%	74%	85%	55%	47%	44%	54%
Saguaro SC 3	0%	0%	0%	0%	0%	2%	6%	1%	5%	0%	0%	0%	1%

Year - 2009

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	92%	99%	101%	71%	81%	100%	100%	100%	100%	69%	93%	91%	91%
Four Corners 1-2-3	70%	52%	63%	100%	100%	100%	100%	100%	62%	100%	90%	94%	86%
Four Corners 4-5	96%	46%	98%	100%	50%	100%	100%	100%	96%	87%	98%	96%	89%
Navajo 1-2-3	67%	60%	56%	100%	100%	100%	100%	100%	83%	100%	99%	99%	89%
Cholla 1-2-3	86%	84%	74%	42%	99%	75%	100%	100%	73%	95%	90%	85%	84%
Hydro	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
W. Phoenix CC 1-3	8%	1%	0%	6%	33%	31%	65%	73%	58%	16%	0%	8%	25%
Ocotillo 1-2	4%	0%	0%	3%	9%	51%	34%	42%	36%	17%	0%	0%	16%
Saguaro 1-2	0%	0%	0%	0%	0%	2%	11%	11%	0%	0%	0%	0%	2%
Yucca CT 1-4	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%
Ocotillo CT 1-2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Saguaro CT 1-2	0%	0%	0%	0%	0%	0%	2%	3%	0%	0%	0%	0%	0%
W. Phoenix CT 1-2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Douglas CT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Future CTs	0%	0%	0%	0%	1%	36%	31%	42%	26%	7%	0%	0%	12%
W. Phoenix CC 4	19%	15%	1%	5%	46%	84%	30%	82%	71%	29%	1%	16%	33%
W. Phoenix CC 5	76%	75%	11%	88%	88%	97%	94%	96%	92%	77%	57%	73%	77%
Redhawk CC 1&2	55%	53%	58%	58%	65%	66%	83%	63%	84%	54%	33%	40%	59%
Saguaro SC 3	0%	0%	0%	0%	0%	0%	4%	3%	0%	0%	0%	0%	1%

APS Capacity Factors

Case 1 - With PWEC Units Available to APS System

Year - 2010

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	92%	98%	101%	59%	91%	100%	100%	100%	91%	68%	94%	101%	91%
Four Corners 1-2-3	91%	88%	68%	54%	73%	100%	100%	100%	100%	77%	92%	95%	86%
Four Corners 4-5	66%	46%	49%	80%	96%	100%	100%	100%	60%	100%	100%	49%	79%
Navajo 1-2-3	97%	58%	70%	100%	100%	100%	100%	100%	60%	80%	100%	99%	89%
Cholla 1-2-3	86%	80%	77%	99%	69%	75%	100%	89%	100%	98%	94%	88%	88%
Hydro	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
W. Phoenix CC 1-3	12%	1%	0%	8%	53%	50%	78%	55%	60%	20%	20%	14%	31%
Ocotillo 1-2	7%	0%	0%	6%	23%	45%	14%	60%	35%	20%	1%	3%	18%
Saguaro 1-2	0%	0%	0%	0%	0%	2%	26%	20%	1%	0%	0%	0%	4%
Yucca CT 1-4	0%	0%	0%	0%	0%	0%	8%	7%	0%	0%	0%	0%	1%
Ocotillo CT 1-2	0%	0%	0%	0%	0%	0%	8%	4%	0%	0%	0%	0%	1%
Saguaro CT 1-2	0%	0%	0%	0%	0%	0%	12%	7%	0%	0%	0%	0%	2%
W. Phoenix CT 1-2	0%	0%	0%	0%	0%	0%	6%	6%	0%	0%	0%	0%	1%
Douglas CT	0%	0%	0%	0%	0%	0%	7%	6%	0%	0%	0%	0%	1%
Future CTs	0%	0%	0%	1%	10%	31%	50%	53%	30%	11%	0%	0%	16%
W. Phoenix CC 4	25%	20%	1%	32%	25%	78%	83%	87%	70%	41%	40%	20%	44%
W. Phoenix CC 5	56%	71%	76%	99%	93%	97%	95%	97%	93%	84%	36%	79%	82%
Redhawk CC 1&2	59%	52%	38%	70%	76%	90%	64%	65%	84%	66%	42%	44%	63%
Saguaro SC 3	0%	0%	0%	0%	0%	0%	0%	13%	0%	0%	0%	0%	1%

Notes: (1) Source is 2003 LRF MAPS run.
(2) Does not reflect potential off-system economy purchases or sales. PWEC units may operate more or less than indicated to benefit from prevailing market conditions.

APS/PWEC Units Operated to Meet Baseload (MW)

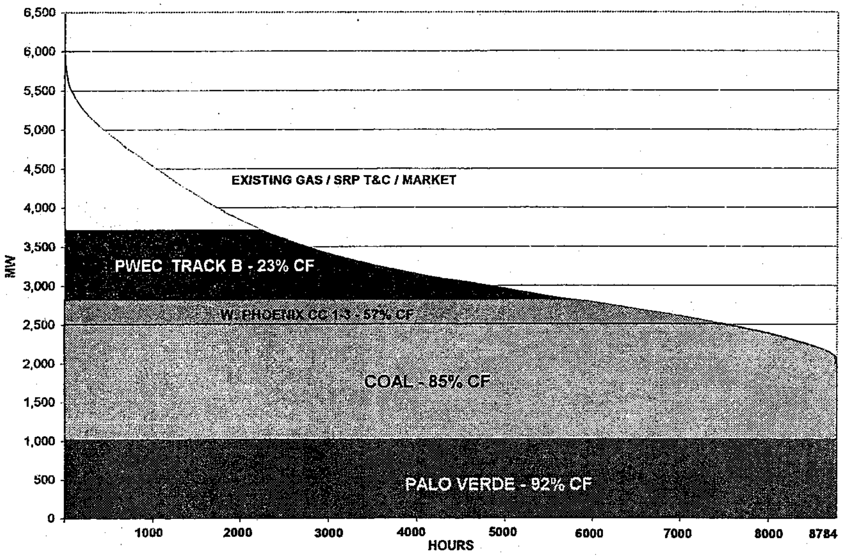
Case 2 (without PWEC Units)[1]

	2004	2005	2006	2007	2008	2009	2010
Summer							
Palo Verde 1-3	1,113	1,113	1,113	1,113	1,113	1,113	1,113
Four Corners 4-5	222	222	222	222	222	222	222
Navajo 1-3	315	315	315	315	315	315	315
Four Corners 1-3	560	560	560	560	560	560	560
Cholla 1-3	615	615	615	615	615	615	615
West Phoenix CC 1-3	240	240	240	240	240	240	240
Ocotillo Steam 1-2			220	220	220	220	220
Saguaro Steam 1-2				210	210	210	210
Ocotillo CT 1-2[2]				100	100	100	100
Saguaro CT 1-2[2]				100	100	100	100
West Phoenix CT 1-2[2]				100	100	100	100
Yucca CT 1-4[2]				139	139	139	139
Douglas CT[2]				15	15	15	15
West Phoenix CC 4	110	110	110				
West Phoenix CC 5	524	524	524				
Redhawk CC 1-2	990	990	990				
Saguaro CT3							
Total	4,689	4,689	4,909	3,949	3,949	3,949	3,949
Annual							
Palo Verde 1-3	1,113	1,113	1,113	1,113	1,113	1,113	1,113
Four Corners 4-5	222	222	222	222	222	222	222
Navajo 1-3	315	315	315	315	315	315	315
Four Corners 1-3	560	560	560	560	560	560	560
Cholla 1-3	615	615	615	615	615	615	615
West Phoenix CC 1-3	255	255	255	255	255	255	255
Ocotillo Steam 1-2		220	220	220	220	220	220
Saguaro Steam 1-2				210	210	210	210
Ocotillo CT 1-2[2]							
Saguaro CT 1-2[2]							
West Phoenix CT 1-2[2]							
Yucca CT 1-4[2]							
Douglas CT[2]							
West Phoenix CC 4							
West Phoenix CC 5							
Redhawk CC 1-2							
Saguaro CT3							
Total	3,080	3,300	3,300	3,510	3,510	3,510	3,510

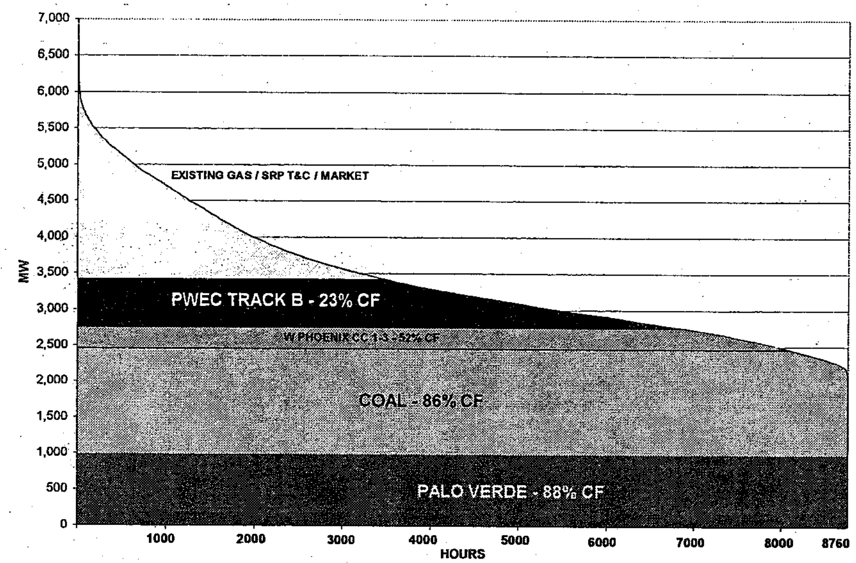
NOTES: 1) Case 2 has PWEC Track B contract for summer months of 2004 - 2006
2) Without the PWEC units and market purchases, APS existing CTs could be forced to baseload operation. It is anticipated that market energy would significantly reduce operation of the CTs indicated above.

APS Load Duration Curve
Case 2 – Without PWEC Units

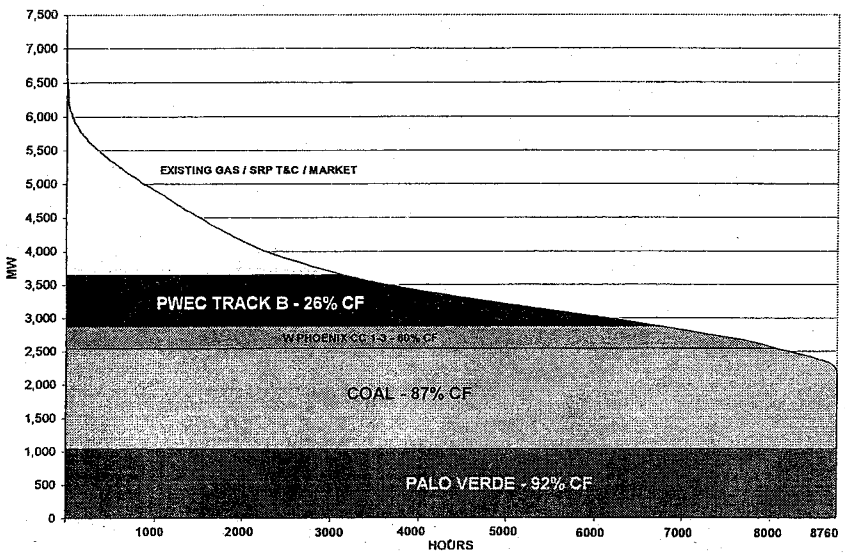
YEAR 2004



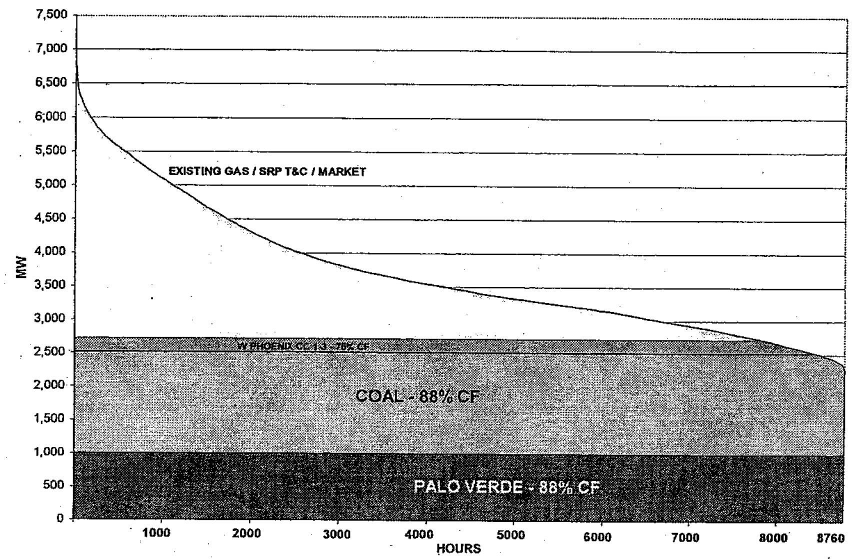
YEAR 2005



YEAR 2006

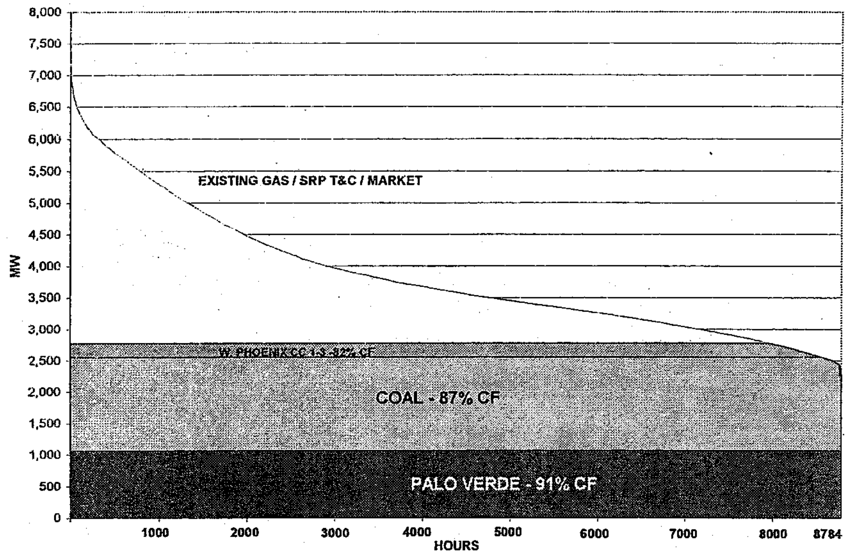


YEAR 2007

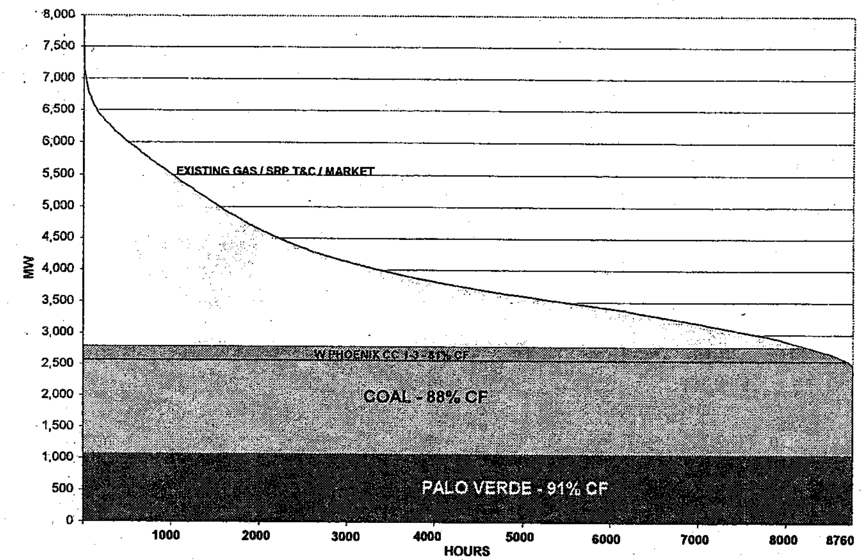


APS Load Duration Curve
Case 2 – Without PWEC Units

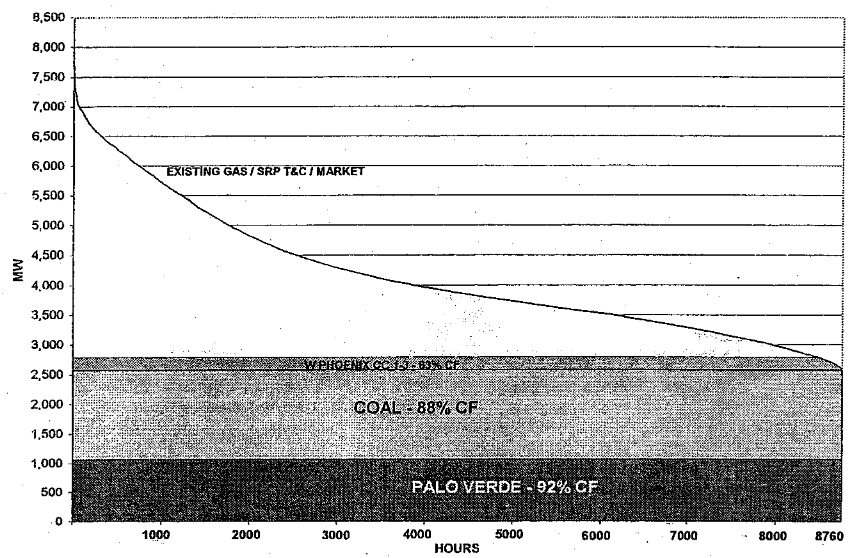
YEAR 2008



YEAR 2009



YEAR 2010



Notes:

(1) Source is MAPS run that continues PWEC Track B summer purchase through 9/2006 and includes Pacificorp Supplemental Sale Obligation. APS load obligation is met through APS existing units to the extent possible.

(2) Does not reflect potential off-system economy purchases or sales.

(3) Following is the resulting unmet energy needs (GWH):

2004	2005	2006	2007	2008	2009	2010
127	594	463	3234	3704	4556	5614

APS Capacity Factors
Case 2 - Without PWEC Units

Year - 2004

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	92%	92%	101%	70%	91%	100%	100%	100%	100%	68%	94%	90%	92%
Four Corners 1-2-3	90%	89%	63%	78%	55%	61%	100%	100%	99%	96%	75%	87%	83%
Four Corners 4-5	68%	48%	50%	98%	100%	52%	50%	100%	100%	92%	100%	97%	80%
Navajo 1-2-3	99%	65%	70%	80%	100%	100%	100%	100%	60%	100%	100%	100%	90%
Cholla 1-2-3	86%	77%	88%	98%	88%	69%	100%	100%	98%	95%	71%	83%	88%
Hydro	95%	93%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
W. Phoenix CC 1-3	65%	55%	58%	78%	92%	53%	29%	22%	33%	74%	81%	46%	57%
Ocotillo 1-2	31%	54%	30%	62%	85%	21%	10%	12%	32%	65%	39%	50%	41%
Saguaro 1-2	40%	37%	3%	27%	72%	4%	6%	7%	10%	44%	40%	33%	27%
Yucca CT 1-4	7%	8%	0%	4%	34%	0%	1%	0%	0%	18%	0%	17%	8%
Ocotillo CT 1-2	22%	11%	0%	26%	57%	0%	2%	0%	0%	24%	2%	29%	15%
Saguaro CT 1-2	25%	28%	1%	18%	52%	0%	5%	0%	0%	15%	20%	36%	17%
W. Phoenix CT 1-2	16%	24%	0%	6%	50%	0%	0%	0%	0%	21%	0%	25%	12%
Douglas CT	10%	1%	0%	4%	32%	0%	0%	0%	0%	23%	0%	11%	7%
W. Phoenix CC 4	0%	0%	0%	0%	0%	27%	56%	54%	60%	0%	0%	0%	16%
W. Phoenix CC 5	0%	0%	0%	0%	0%	96%	90%	89%	85%	0%	0%	0%	30%
Redhawk CC 1&2	0%	0%	0%	0%	0%	85%	71%	64%	29%	0%	0%	0%	21%
Saguaro SC 3	0%	0%	0%	0%	0%	0%	5%	0%	4%	0%	0%	0%	1%

Year - 2005

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	101%	93%	101%	67%	92%	100%	90%	100%	100%	58%	68%	86%	88%
Four Corners 1-2-3	92%	75%	28%	100%	39%	100%	100%	100%	100%	100%	100%	95%	86%
Four Corners 4-5	93%	97%	100%	70%	100%	50%	100%	90%	100%	50%	83%	100%	86%
Navajo 1-2-3	74%	66%	94%	76%	63%	100%	100%	100%	100%	100%	100%	100%	90%
Cholla 1-2-3	83%	83%	92%	64%	38%	100%	99%	99%	97%	98%	74%	85%	84%
Hydro	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
W. Phoenix CC 1-3	48%	50%	53%	64%	104%	22%	52%	54%	10%	52%	66%	52%	52%
Ocotillo 1-2	49%	31%	36%	94%	100%	4%	28%	29%	8%	87%	89%	55%	51%
Saguaro 1-2	44%	40%	16%	82%	99%	1%	12%	22%	3%	66%	34%	50%	39%
Yucca CT 1-4	17%	37%	25%	51%	75%	0%	1%	8%	0%	51%	56%	33%	29%
Ocotillo CT 1-2	23%	0%	19%	50%	98%	0%	1%	6%	0%	47%	49%	29%	27%
Saguaro CT 1-2	21%	37%	15%	62%	29%	0%	5%	7%	0%	57%	67%	37%	28%
W. Phoenix CT 1-2	17%	30%	1%	33%	92%	0%	4%	4%	0%	30%	36%	25%	23%
Douglas CT	13%	24%	2%	22%	85%	0%	2%	4%	0%	38%	20%	19%	19%
W. Phoenix CC 4	0%	0%	0%	0%	0%	54%	63%	69%	36%	0%	0%	0%	19%
W. Phoenix CC 5	0%	0%	0%	0%	0%	93%	92%	91%	84%	0%	0%	0%	30%
Redhawk CC 1&2	0%	0%	0%	0%	0%	74%	78%	57%	53%	0%	0%	0%	22%
Saguaro SC 3	0%	0%	0%	0%	0%	0%	0%	15%	0%	0%	0%	0%	1%

Note: (1) Includes PWEC Track B Contract.

APS Capacity Factors
Case 2 - Without PWEC Units

Year - 2006

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	101%	81%	101%	69%	94%	91%	100%	100%	99%	66%	96%	101%	92%
Four Corners 1-2-3	91%	35%	68%	100%	100%	100%	100%	100%	100%	100%	23%	92%	85%
Four Corners 4-5	49%	99%	100%	100%	97%	100%	93%	50%	100%	94%	92%	97%	89%
Navajo 1-2-3	79%	100%	71%	98%	100%	100%	58%	100%	100%	100%	100%	99%	92%
Cholla 1-2-3	76%	68%	83%	58%	74%	100%	100%	99%	98%	96%	100%	81%	86%
Hydro	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
W. Phoenix CC 1-3	83%	62%	32%	86%	64%	41%	58%	53%	18%	82%	77%	63%	60%
Ocotillo 1-2	64%	80%	62%	87%	87%	12%	53%	37%	9%	71%	66%	51%	56%
Saguaro 1-2	41%	71%	28%	76%	84%	8%	36%	21%	8%	67%	45%	35%	43%
Yucca CT 1-4	18%	42%	0%	26%	35%	0%	11%	6%	0%	29%	34%	17%	18%
Ocotillo CT 1-2	34%	64%	3%	59%	76%	0%	0%	5%	0%	33%	67%	33%	31%
Saguaro CT 1-2	25%	69%	24%	52%	41%	0%	17%	9%	0%	42%	81%	39%	33%
W. Phoenix CT 1-2	29%	47%	2%	44%	68%	0%	8%	5%	0%	14%	50%	28%	24%
Douglas CT	27%	40%	0%	27%	56%	0%	8%	5%	0%	29%	25%	18%	20%
W. Phoenix CC 4	0%	0%	0%	0%	0%	61%	68%	69%	48%	0%	0%	0%	21%
W. Phoenix CC 5	0%	0%	0%	0%	0%	86%	94%	92%	86%	0%	0%	0%	30%
Redhawk CC 1&2	0%	0%	0%	0%	0%	83%	82%	78%	63%	0%	0%	0%	26%
Saguaro SC 3	0%	0%	0%	0%	0%	3%	0%	21%	2%	0%	0%	0%	2%

Year - 2007

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	92%	101%	100%	59%	94%	90%	100%	100%	98%	68%	69%	89%	88%
Four Corners 1-2-3	94%	47%	83%	100%	100%	77%	98%	100%	100%	99%	53%	87%	87%
Four Corners 4-5	98%	96%	100%	87%	76%	50%	50%	100%	100%	100%	100%	100%	88%
Navajo 1-2-3	99%	97%	70%	99%	100%	80%	78%	100%	80%	100%	100%	100%	92%
Cholla 1-2-3	88%	85%	83%	84%	98%	100%	69%	89%	99%	94%	75%	89%	88%
Hydro	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
W. Phoenix CC 1-3	59%	54%	53%	75%	84%	48%	94%	92%	68%	82%	103%	81%	75%
Ocotillo 1-2	68%	68%	42%	91%	87%	66%	100%	96%	95%	76%	99%	44%	78%
Saguaro 1-2	56%	57%	15%	84%	83%	100%	100%	94%	91%	71%	35%	52%	70%
Yucca CT 1-4	27%	27%	2%	47%	55%	81%	87%	49%	73%	36%	65%	20%	47%
Ocotillo CT 1-2	19%	40%	34%	58%	55%	91%	86%	39%	73%	39%	97%	47%	56%
Saguaro CT 1-2	42%	36%	35%	41%	79%	91%	88%	80%	38%	46%	104%	51%	61%
W. Phoenix CT 1-2	19%	19%	7%	70%	69%	90%	84%	75%	70%	30%	68%	45%	54%
Douglas CT	26%	26%	2%	52%	53%	0%	90%	81%	73%	29%	55%	35%	44%

Note: (1) Includes PWEC Track B Contract.

APS Capacity Factors
Case 2 - Without PWEC Units

Year - 2008

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	101%	101%	89%	67%	97%	100%	100%	100%	100%	61%	92%	91%	91%
Four Corners 1-2-3	73%	92%	100%	95%	71%	100%	61%	100%	68%	100%	91%	89%	87%
Four Corners 4-5	77%	48%	50%	92%	97%	50%	100%	100%	100%	84%	100%	59%	80%
Navajo 1-2-3	99%	96%	69%	100%	62%	100%	100%	100%	100%	76%	100%	100%	92%
Cholla 1-2-3	89%	60%	83%	100%	100%	70%	100%	99%	88%	73%	97%	92%	88%
Hydro	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
W. Phoenix CC 1-3	61%	81%	88%	85%	101%	42%	94%	90%	69%	89%	92%	87%	82%
Ocotillo 1-2	75%	68%	72%	90%	93%	100%	100%	95%	63%	61%	52%	75%	79%
Saguaro 1-2	51%	49%	59%	84%	90%	100%	100%	94%	98%	88%	19%	40%	73%
Yucca CT 1-4	33%	29%	3%	23%	73%	84%	89%	77%	82%	64%	23%	44%	52%
Ocotillo CT 1-2	51%	45%	37%	33%	45%	69%	86%	75%	85%	65%	42%	52%	57%
Saguaro CT 1-2	63%	27%	23%	76%	91%	91%	89%	77%	67%	67%	52%	59%	65%
W. Phoenix CT 1-2	41%	39%	14%	48%	89%	87%	85%	73%	80%	62%	27%	39%	57%
Douglas CT	34%	27%	3%	49%	71%	95%	91%	79%	86%	51%	0%	44%	52%

Year - 2009

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	92%	101%	101%	71%	81%	100%	100%	100%	100%	69%	93%	91%	91%
Four Corners 1-2-3	74%	55%	67%	100%	100%	100%	100%	100%	62%	100%	91%	98%	87%
Four Corners 4-5	100%	49%	100%	100%	50%	100%	100%	100%	96%	87%	98%	98%	90%
Navajo 1-2-3	69%	66%	56%	100%	100%	100%	100%	100%	83%	100%	100%	100%	90%
Cholla 1-2-3	95%	91%	81%	44%	99%	75%	100%	100%	74%	98%	96%	90%	87%
Hydro	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
W. Phoenix CC 1-3	70%	75%	91%	104%	103%	39%	94%	94%	94%	61%	64%	87%	81%
Ocotillo 1-2	84%	75%	56%	65%	62%	100%	99%	100%	99%	91%	83%	73%	82%
Saguaro 1-2	79%	64%	56%	94%	92%	100%	97%	100%	98%	84%	52%	13%	77%
Yucca CT 1-4	48%	46%	19%	60%	72%	58%	84%	88%	62%	63%	40%	47%	57%
Ocotillo CT 1-2	68%	67%	51%	83%	91%	45%	80%	66%	65%	65%	33%	58%	64%
Saguaro CT 1-2	58%	73%	64%	96%	93%	91%	85%	89%	43%	66%	36%	48%	70%
W. Phoenix CT 1-2	64%	61%	39%	40%	88%	89%	79%	84%	81%	60%	45%	16%	62%
Douglas CT	46%	44%	19%	69%	69%	98%	86%	89%	88%	0%	39%	48%	58%

APS Capacity Factors

Case 2 - Without PWEC Units

Year - 2010

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Palo Verde	92%	101%	101%	59%	91%	100%	100%	100%	91%	68%	94%	101%	91%
Four Corners 1-2-3	95%	95%	72%	54%	73%	100%	100%	100%	100%	77%	92%	98%	88%
Four Corners 4-5	68%	49%	50%	80%	96%	100%	100%	100%	60%	100%	100%	50%	80%
Navajo 1-2-3	99%	66%	70%	100%	100%	100%	100%	100%	60%	80%	100%	100%	90%
Cholla 1-2-3	93%	88%	87%	99%	69%	75%	100%	89%	100%	99%	98%	92%	91%
Hydro	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
W. Phoenix CC 1-3	83%	68%	84%	95%	104%	65%	94%	65%	94%	65%	95%	89%	83%
Ocotillo 1-2	82%	75%	85%	100%	100%	100%	30%	100%	99%	95%	82%	55%	84%
Saguaro 1-2	73%	60%	61%	62%	97%	100%	100%	100%	97%	92%	44%	52%	78%
Yucca CT 1-4	45%	34%	39%	77%	84%	93%	83%	83%	23%	70%	38%	45%	60%
Ocotillo CT 1-2	66%	62%	67%	102%	96%	70%	87%	45%	42%	72%	63%	48%	68%
Saguaro CT 1-2	35%	65%	58%	109%	101%	91%	89%	70%	86%	78%	72%	33%	74%
W. Phoenix CT 1-2	61%	53%	43%	95%	71%	89%	87%	89%	81%	67%	27%	30%	66%
Douglas CT	44%	39%	0%	76%	84%	97%	93%	96%	89%	71%	37%	42%	64%

Notes: (1) Source is a MAPS run that continues PWEC Track B summer purchase through 9/2006 and includes Pacificorp Supplemental Sale Obligation. APS load obligation is met through APS existing units to the extent possible.
(2) Does not reflect potential off-system economy purchases or sales.

APS SUPPLY & DEMAND BALANCE
Year 2004
Case 1 (PWEC Units Available to APS System)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	3,906	3,663	3,356	3,865	4,885	5,463	6,023	6,023	5,441	4,517	3,383	3,908
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	492	463	368	429	494	703	787	787	700	564	428	491
3	TOTAL LOAD REQUIREMENTS	4,398	4,126	3,724	4,294	5,379	6,166	6,810	6,810	6,141	5,081	3,811	4,399
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,007	4,007	4,007	4,007	4,007	4,007	4,007	4,007	4,007	4,007	4,007	4,007
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(309)	(414)	(360)	(622)	0	0	0	0	0	0	(110)	(100)
7	TOTAL	3,784	3,679	3,647	3,385	4,007	3,953	3,953	3,953	3,953	4,007	3,983	3,993
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	288	288	288	288	288	295	295	295	295	295	295	295
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	10	10	10	10	10	10	10	10	10	10	10	10
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(120)	(120)	360	360	840	847	847	847	847	(113)	(113)	(113)
14	TOTAL EXISTING RESOURCES	3,664	3,559	4,007	3,745	4,847	4,800	4,800	4,800	4,800	3,894	3,870	3,880
	C. EXISTING RESOURCES OVER / (UNDER)	(734)	(567)	283	(550)	(532)	(1,367)	(2,011)	(2,011)	(1,341)	(1,188)	59	(519)
	D. FUTURE RESOURCES												
15	PWEC's WEST PHOENIX CC 4						110	110	110	110			
16	PWEC's WEST PHOENIX CC 5						524	524	524	524			
17	PWEC's REDHAWK 1-2						990	990	990	990			
18	PWEC's SAGUARO SC						76	76	76	76			
19	PPL's SUNDANCE CTs						150	150	150	150			
20	PANDA's GILA RIVER	225	225	225	225	450	0	0	0	0	450	225	225
21	CAPACITY ON MAINTENANCE						0	0	0	0			
22	TOTAL	225	225	225	225	450	1,850	1,850	1,850	1,850	450	225	225
23	TOTAL EXISTING EXISTING AND NEW RESOURCES	3,889	3,784	4,232	3,970	5,297	6,650	6,650	6,650	6,650	4,344	4,095	4,105
	E. ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	(509)	(342)	508	(325)	(82)	483	(161)	(161)	509	(738)	284	(294)

APS SUPPLY & DEMAND BALANCE
Year 2005
Case 1 (PWEC Units Available to APS System)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	4,072	3,907	3,497	4,026	5,091	5,678	6,269	6,269	5,669	4,708	3,526	4,071
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	511	491	384	448	518	734	823	823	733	586	445	510
3	TOTAL LOAD REQUIREMENTS	4,583	4,398	3,881	4,473	5,609	6,413	7,092	7,092	6,402	5,295	3,971	4,580
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(193)	(583)	(580)	(841)	0	0	0	0	0	0	(368)	(368)
7	TOTAL	3,895	3,505	3,422	3,161	4,002	3,948	3,948	3,948	3,948	4,002	3,721	3,721
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	295	295	295	295	295	302	302	302	302	302	302	302
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	18	18	18	18	18	18	18	18	18	18	18	18
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(105)	(105)	375	375	855	862	862	862	862	(98)	(98)	(98)
14	TOTAL EXISTING RESOURCES	3,790	3,400	3,797	3,536	4,857	4,810	4,810	4,810	4,810	3,904	3,623	3,623
	C. EXISTING RESOURCES OVER / (UNDER)	(792)	(997)	(83)	(937)	(751)	(1,602)	(2,282)	(2,282)	(1,592)	(1,390)	(348)	(957)
	D. FUTURE RESOURCES												
15	PWEC's WEST PHOENIX CC 4	120	120	112	112	112	110	110	110	110	112	120	120
16	PWEC's WEST PHOENIX CC 5	528	528	506	506	506	524	524	524	524	506	528	528
17	PWEC's REDHAWK 1-2	1,012	1,012	984	984	984	990	990	990	990	984	1,012	1,012
18	PWEC's SAGUARO SC	79	79	79	79	79	76	76	76	76	79	79	79
19	PPL's SUNDANCE CTs						150	150	150	150			
20	PANDA's GILA RIVER	225	225	225	225	450							
21	CAPACITY ON MAINTENANCE	(253)	0	(246)	0	(246)	0	0	0	0	(253)	0	0
22	TOTAL	1,711	1,964	1,660	1,906	1,885	1,850	1,850	1,850	1,850	1,428	1,739	1,739
23	TOTAL EXISTING EXISTING AND NEW RESOURCES	5,501	5,364	5,457	5,442	6,742	6,660	6,660	6,660	6,660	5,332	5,362	5,362
	E. ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	918	967	1,577	969	1,134	248	(432)	(432)	258	38	1,391	782

APS SUPPLY & DEMAND BALANCE
Year 2006
Case 1 (PWEC Units Available to APS System)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	4,238	4,063	3,637	4,187	5,296	5,911	6,522	6,522	5,899	4,898	3,668	4,237
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	530	509	400	466	542	768	860	860	766	608	461	529
3	TOTAL LOAD REQUIREMENTS	4,768	4,572	4,037	4,653	5,837	6,679	7,382	7,382	6,665	5,506	4,129	4,766
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(88)	(88)	(450)	(453)	0	0	0	0	0	0	(380)	0
7	TOTAL	4,027	4,027	3,579	3,575	4,029	3,975	3,975	3,975	3,975	4,029	3,735	4,115
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	302	302	302	302	302	310	310	310	310	310	310	310
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	18	18	18	18	18	18	18	18	18	18	18	18
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(98)	(98)	382	382	862	870	870	870	870	(90)	(90)	(90)
14	TOTAL EXISTING RESOURCES	3,929	3,929	3,961	3,957	4,891	4,845	4,845	4,845	4,845	3,939	3,645	4,025
	C. EXISTING RESOURCES OVER / (UNDER)	(839)	(644)	(76)	(695)	(946)	(1,834)	(2,537)	(2,537)	(1,820)	(1,567)	(484)	(741)
	D. FUTURE RESOURCES												
15	WEST PHOENIX CC 4	120	120	112	112	112	110	110	110	110	112	120	120
16	WEST PHOENIX CC 5	528	528	506	506	506	524	524	524	524	506	528	528
17	REDHAWK 1-2	1,012	1,012	984	984	984	990	990	990	990	984	1,012	1,012
18	SAGUARO SC	79	79	79	79	79	76	76	76	76	79	79	79
19	CAPACITY ON MAINTENANCE	0	(112)	(492)	0	0	0	0	0	0	0	(528)	(506)
20	TOTAL	1,739	1,627	1,189	1,681	1,681	1,700	1,700	1,700	1,700	1,681	1,211	1,233
21	TOTAL EXISTING EXISTING AND NEW RESOURCES	5,668	5,556	5,150	5,638	6,572	6,545	6,545	6,545	6,545	5,620	4,856	5,257
	E. ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	900	983	1,113	986	735	(134)	(837)	(837)	(120)	114	727	492

APS SUPPLY & DEMAND BALANCE
Year 2007
Case 1 (PWEC Units Available to APS System)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	4,410	4,229	3,784	4,357	5,511	6,151	6,787	6,787	6,138	5,097	3,817	4,409
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	550	528	417	486	566	803	898	898	801	631	477	549
3	TOTAL LOAD REQUIREMENTS	4,960	4,756	4,201	4,842	6,077	6,954	7,686	7,686	6,939	5,728	4,295	4,958
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(88)	(258)	(688)	(584)	0	0	0	0	0	0	(463)	(463)
7	TOTAL	4,027	3,857	3,341	3,445	4,029	3,975	3,975	3,975	3,975	4,029	3,652	3,652
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	310	310	310	310	310	318	318	318	318	318	318	318
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	21	21	21	21	21	21	21	21	21	21	21	21
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(87)	(87)	393	393	873	881	881	881	881	(79)	(79)	(79)
14	TOTAL EXISTING RESOURCES	3,940	3,770	3,734	3,838	4,902	4,856	4,856	4,856	4,856	3,950	3,573	3,573
	C. EXISTING RESOURCES OVER / (UNDER)	(1,020)	(987)	(467)	(1,005)	(1,176)	(2,098)	(2,830)	(2,830)	(2,084)	(1,778)	(722)	(1,385)
	D. FUTURE RESOURCES												
15	WEST PHOENIX CC 4	120	120	112	112	112	110	110	110	110	112	120	120
16	WEST PHOENIX CC 5	528	528	506	506	506	524	524	524	524	506	528	528
17	REDHAWK 1-2	1,012	1,012	984	984	984	990	990	990	990	984	1,012	1,012
18	SAGUARO SC	79	79	79	79	79	76	76	76	76	79	79	79
19	CAPACITY ON MAINTENANCE	0	(253)	(492)	(253)	(112)	0	0	0	0	(253)	0	(253)
20	TOTAL	1,739	1,486	1,189	1,428	1,569	1,700	1,700	1,700	1,700	1,428	1,739	1,486
21	TOTAL EXISTING EXISTING AND NEW RESOURCES	5,679	5,256	4,923	5,266	6,471	6,556	6,556	6,556	6,556	5,378	5,312	5,059
	E. ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	719	499	722	423	393	(398)	(1,130)	(1,130)	(384)	(350)	1,017	101

APS SUPPLY & DEMAND BALANCE
Year 2008
Case 1 (PWEC Units Available to APS System)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	4,590	4,401	3,939	4,535	5,736	6,402	7,064	7,064	6,389	5,305	3,973	4,589
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	570	548	434	506	593	839	939	939	837	655	495	569
3	TOTAL LOAD REQUIREMENTS	5,160	4,949	4,373	5,041	6,328	7,241	8,003	8,003	7,226	5,960	4,468	5,158
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(331)	(444)	(604)	(643)	(170)	0	0	0	0	0	(100)	0
7	TOTAL	3,810	3,697	3,451	3,412	3,885	4,001	4,001	4,001	4,001	4,055	4,041	4,141
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	318	318	318	318	318	326	326	326	326	326	326	326
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	22	22	22	22	22	22	22	22	22	22	22	22
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(78)	(78)	402	402	882	890	890	890	890	(70)	(70)	(70)
14	TOTAL EXISTING RESOURCES	3,732	3,619	3,853	3,814	4,767	4,891	4,891	4,891	4,891	3,985	3,971	4,071
	C. EXISTING RESOURCES OVER / (UNDER)	(1,429)	(1,330)	(520)	(1,227)	(1,561)	(2,350)	(3,112)	(3,112)	(2,335)	(1,975)	(497)	(1,088)
	D. FUTURE RESOURCES												
15	WEST PHOENIX CC 4	120	120	112	112	112	110	110	110	110	112	120	120
16	WEST PHOENIX CC 5	528	528	506	506	506	524	524	524	524	506	528	528
17	REDHAWK 1-2	1,012	1,012	984	984	984	990	990	990	990	984	1,012	1,012
18	SAGUARO SC	79	79	79	79	79	76	76	76	76	79	79	79
19	CAPACITY ON MAINTENANCE	0	0	(492)	(253)	0	0	0	0	0	(499)	(253)	0
20	TOTAL	1,739	1,739	1,189	1,428	1,681	1,700	1,700	1,700	1,700	1,182	1,486	1,739
21	TOTAL EXISTING EXISTING AND NEW RESOURCES	5,471	5,358	5,042	5,242	6,448	6,591	6,591	6,591	6,591	5,167	5,457	5,810
	E. ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	310	409	669	201	120	(650)	(1,412)	(1,412)	(635)	(793)	989	651

APS SUPPLY & DEMAND BALANCE
Year 2009
Case 1 (PWEC Units Available to APS System)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	4,780	4,583	4,102	4,722	5,973	6,667	7,357	7,357	6,653	5,524	4,137	4,779
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	592	568	453	528	620	878	981	981	876	680	514	591
3	TOTAL LOAD REQUIREMENTS	5,372	5,152	4,555	5,250	6,593	7,544	8,338	8,338	7,529	6,205	4,651	5,370
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(193)	(325)	(260)	(649)	0	0	0	0	0	0	(358)	0
7	TOTAL	3,948	3,816	3,795	3,406	4,055	4,001	4,001	4,001	4,001	4,055	3,783	4,141
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	326	326	326	326	326	334	334	334	334	334	334	334
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	22	22	22	22	22	22	22	22	22	22	22	22
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(70)	(70)	410	410	890	898	898	898	898	(62)	(62)	(62)
14	TOTAL EXISTING RESOURCES	3,878	3,746	4,205	3,816	4,945	4,899	4,899	4,899	4,899	3,993	3,721	4,079
	C. EXISTING RESOURCES OVER / (UNDER)	(1,494)	(1,406)	(350)	(1,434)	(1,648)	(2,646)	(3,439)	(3,439)	(2,630)	(2,212)	(930)	(1,291)
	D. FUTURE RESOURCES												
15	WEST PHOENIX CC 4	120	120	112	112	112	110	110	110	110	112	120	120
16	WEST PHOENIX CC 5	528	528	506	506	506	524	524	524	524	506	528	528
17	REDHAWK 1-2	1,012	1,012	984	984	984	990	990	990	990	984	1,012	1,012
18	SAGUARO SC	79	79	79	79	79	76	76	76	76	79	79	79
19	CAPACITY ON MAINTENANCE	(253)	(499)	(499)	0	(112)	0	0	0	0	(253)	(264)	0
20	TOTAL	1,486	1,240	1,182	1,681	1,569	1,700	1,700	1,700	1,700	1,428	1,475	1,739
21	TOTAL EXISTING EXISTING AND NEW RESOURCES	5,364	4,986	5,387	5,497	6,514	6,599	6,599	6,599	6,599	5,421	5,196	5,818
	E. ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	(8)	(166)	832	247	(79)	(946)	(1,739)	(1,739)	(930)	(784)	545	448

APS SUPPLY & DEMAND BALANCE
Year 2010
Case 1 (PWEC Units Available to APS System)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	4,982	4,776	4,275	4,921	6,225	6,948	7,667	7,667	6,934	5,757	4,312	4,981
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	615	591	473	550	649	919	1,027	1,027	917	707	534	614
3	TOTAL LOAD REQUIREMENTS	5,597	5,367	4,748	5,472	6,874	7,867	8,694	8,694	7,850	6,464	4,846	5,595
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(199)	(414)	(411)	(643)	(170)	0	0	0	0	0	(210)	(210)
7	TOTAL	3,942	3,727	3,644	3,412	3,885	4,001	4,001	4,001	4,001	4,055	3,931	3,931
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	334	334	334	334	334	342	342	342	342	342	342	342
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	23	23	23	23	23	23	23	23	23	23	23	23
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(61)	(61)	419	419	899	907	907	907	907	(53)	(53)	(53)
14	TOTAL EXISTING RESOURCES	3,881	3,666	4,063	3,831	4,784	4,908	4,908	4,908	4,908	4,002	3,878	3,878
	C. EXISTING RESOURCES OVER / (UNDER)	(1,716)	(1,701)	(685)	(1,641)	(2,090)	(2,959)	(3,786)	(3,786)	(2,943)	(2,463)	(968)	(1,717)
	D. FUTURE RESOURCES												
15	WEST PHOENIX CC 4	120	120	112	112	112	110	110	110	110	112	120	120
16	WEST PHOENIX CC 5	528	528	506	506	506	524	524	524	524	506	528	528
17	REDHAWK 1-2	1,012	1,012	984	984	984	990	990	990	990	984	1,012	1,012
18	SAGUARO SC	79	79	79	79	79	76	76	76	76	79	79	79
19	CAPACITY ON MAINTENANCE	0	0	(492)	(253)	(112)	0	0	0	0	(253)	0	(253)
20	TOTAL	1,739	1,739	1,189	1,428	1,569	1,700	1,700	1,700	1,700	1,428	1,739	1,486
21	TOTAL EXISTING EXISTING AND NEW RESOURCES	5,620	5,405	5,252	5,259	6,353	6,608	6,608	6,608	6,608	5,430	5,617	5,364
	E. ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	23	38	504	(213)	(521)	(1,259)	(2,086)	(2,086)	(1,243)	(1,035)	771	(231)

APS SUPPLY & DEMAND BALANCE
Year 2004
Case 2 (without PWEC Units)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	3,906	3,663	3,356	3,865	4,885	5,463	6,023	6,023	5,441	4,517	3,383	3,908
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	492	463	368	429	494	703	787	787	700	564	428	491
3	TOTAL LOAD REQUIREMENTS	4,398	4,126	3,724	4,294	5,379	6,166	6,810	6,810	6,141	5,081	3,811	4,399
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,007	4,007	4,007	4,007	4,007	4,007	4,007	4,007	4,007	4,007	4,007	4,007
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(309)	(414)	(360)	(622)	0	0	0	0	0	0	(110)	(100)
7	TOTAL	3,784	3,679	3,647	3,385	4,007	3,953	3,953	3,953	3,953	4,007	3,983	3,993
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	288	288	288	288	288	295	295	295	295	295	295	295
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	10	10	10	10	10	10	10	10	10	10	10	10
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(120)	(120)	360	360	840	847	847	847	847	(113)	(113)	(113)
14	TOTAL EXISTING RESOURCES	3,664	3,559	4,007	3,745	4,847	4,800	4,800	4,800	4,800	3,894	3,870	3,880
	C. EXISTING RESOURCES OVER / (UNDER)	(734)	(567)	283	(550)	(532)	(1,367)	(2,011)	(2,011)	(1,341)	(1,188)	59	(519)
	D. FUTURE RESOURCES												
15	PWEC's WEST PHOENIX CC 4						110	110	110	110			
16	PWEC's WEST PHOENIX CC 5						524	524	524	524			
17	PWEC's REDHAWK 1-2						990	990	990	990			
18	PWEC's SAGUARO SC						76	76	76	76			
19	PPL's SUNDANCE CTs						150	150	150	150			
20	PANDA's GILA RIVER	225	225	225	225	450	0	0	0	0	450	225	225
21	TOTAL	225	225	225	225	450	1,850	1,850	1,850	1,850	450	225	225
22	TOTAL EXISTING EXISTING AND NEW RESOURCES	3,889	3,784	4,232	3,970	5,297	6,650	6,650	6,650	6,650	4,344	4,095	4,105
	E. ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	(509)	(342)	508	(325)	(82)	483	(161)	(161)	509	(738)	284	(294)

Note: Case 2 has PWEC Track B contract

APS SUPPLY & DEMAND BALANCE
Year 2005
Case 2 (without PWEC Units)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	4,072	3,907	3,497	4,026	5,091	5,678	6,269	6,269	5,669	4,708	3,526	4,071
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	511	491	384	448	518	734	823	823	733	586	445	510
3	TOTAL LOAD REQUIREMENTS	4,583	4,398	3,881	4,473	5,609	6,413	7,092	7,092	6,402	5,295	3,971	4,580
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(193)	(583)	(580)	(841)	0	0	0	0	0	0	(368)	(368)
7	TOTAL	3,895	3,505	3,422	3,161	4,002	3,948	3,948	3,948	3,948	4,002	3,721	3,721
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	295	295	295	295	295	302	302	302	302	302	302	302
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	18	18	18	18	18	18	18	18	18	18	18	18
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(105)	(105)	375	375	855	862	862	862	862	(98)	(98)	(98)
14	TOTAL EXISTING RESOURCES	3,790	3,400	3,797	3,536	4,857	4,810	4,810	4,810	4,810	3,904	3,623	3,623
	C. EXISTING RESOURCES OVER / (UNDER)	(792)	(997)	(83)	(937)	(751)	(1,602)	(2,282)	(2,282)	(1,592)	(1,390)	(348)	(957)
	D. FUTURE RESOURCES												
15	PWEC's WEST PHOENIX CC 4						110	110	110	110			
16	PWEC's WEST PHOENIX CC 5						524	524	524	524			
17	PWEC's REDHAWK 1-2						990	990	990	990			
18	PWEC's SAGUARO SC						76	76	76	76			
19	PPL's SUNDANCE CTs						150	150	150	150			
20	PANDA's GILA RIVER	225	225	225	225	450							
21	TOTAL	225	225	225	225	450	1,850	1,850	1,850	1,850	0	0	0
22	TOTAL EXISTING EXISTING AND NEW RESOURCES	4,015	3,625	4,022	3,761	5,307	6,660	6,660	6,660	6,660	3,904	3,623	3,623
	E. ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	(567)	(772)	142	(712)	(301)	248	(432)	(432)	258	(1,390)	(348)	(957)

Note: Case 2 has PWEC Track B contract

APS SUPPLY & DEMAND BALANCE
Year 2006
Case 2 (without PWEC Units)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	4,238	4,063	3,637	4,187	5,296	5,911	6,522	6,522	5,899	4,898	3,668	4,237
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	530	509	400	466	542	768	860	860	766	608	461	529
3	TOTAL LOAD REQUIREMENTS	4,768	4,572	4,037	4,653	5,837	6,679	7,382	7,382	6,665	5,506	4,129	4,766
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(88)	(88)	(450)	(453)	0	0	0	0	0	0	(380)	0
7	TOTAL	4,027	4,027	3,579	3,575	4,029	3,975	3,975	3,975	3,975	4,029	3,735	4,115
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	302	302	302	302	302	310	310	310	310	310	310	310
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	18	18	18	18	18	18	18	18	18	18	18	18
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(98)	(98)	382	382	862	870	870	870	870	(90)	(90)	(90)
14	TOTAL EXISTING RESOURCES	3,929	3,929	3,961	3,957	4,891	4,845	4,845	4,845	4,845	3,939	3,645	4,025
	C. EXISTING RESOURCES OVER / (UNDER)	(839)	(644)	(76)	(695)	(946)	(1,834)	(2,537)	(2,537)	(1,820)	(1,567)	(484)	(741)
	D. FUTURE RESOURCES												
15	WEST PHOENIX CC 4						110	110	110	110			
16	WEST PHOENIX CC 5						524	524	524	524			
17	REDHAWK 1-2						990	990	990	990			
18	SAGUARO SC						76	76	76	76			
19	CAPACITY ON MAINTENANCE	0	0	0	0	0	0	0	0	0	0	0	0
20	TOTAL	0	0	0	0	0	1,700	1,700	1,700	1,700	0	0	0
21	TOTAL EXISTING EXISTING AND NEW RESOURCES	3,929	3,929	3,961	3,957	4,891	6,545	6,545	6,545	6,545	3,939	3,645	4,025
	E. ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	(839)	(644)	(76)	(695)	(946)	(134)	(837)	(837)	(120)	(1,567)	(484)	(741)

Note: Case 2 has PWEC Track B contract

APS SUPPLY & DEMAND BALANCE
Year 2007
Case 2 (without PWEC Units)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	4,410	4,229	3,784	4,357	5,511	6,151	6,787	6,787	6,138	5,097	3,817	4,409
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	550	528	417	486	566	803	898	898	801	631	477	549
3	TOTAL LOAD REQUIREMENTS	4,960	4,756	4,201	4,842	6,077	6,954	7,686	7,686	6,939	5,728	4,295	4,958
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(88)	(258)	(688)	(584)	0	0	0	0	0	0	(463)	(463)
7	TOTAL	4,027	3,857	3,341	3,445	4,029	3,975	3,975	3,975	3,975	4,029	3,652	3,652
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	310	310	310	310	310	318	318	318	318	318	318	318
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	21	21	21	21	21	21	21	21	21	21	21	21
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(87)	(87)	393	393	873	881	881	881	881	(79)	(79)	(79)
14	TOTAL EXISTING RESOURCES	3,940	3,770	3,734	3,838	4,902	4,856	4,856	4,856	4,856	3,950	3,573	3,573
	C. EXISTING RESOURCES OVER / (UNDER)	(1,020)	(987)	(467)	(1,005)	(1,176)	(2,098)	(2,830)	(2,830)	(2,084)	(1,778)	(722)	(1,385)
	D. FUTURE RESOURCES												
15	WEST PHOENIX CC 4												
16	WEST PHOENIX CC 5												
17	REDHAWK 1-2												
18	SAGUARO SC												
19	TOTAL	0	0	0	0	0	0	0	0	0	0	0	0
20	TOTAL EXISTING EXISTING AND NEW RESOURCES	3,940	3,770	3,734	3,838	4,902	4,856	4,856	4,856	4,856	3,950	3,573	3,573
	E. ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	(1,020)	(987)	(467)	(1,005)	(1,176)	(2,098)	(2,830)	(2,830)	(2,084)	(1,778)	(722)	(1,385)

Note: Case 2 has PWEC Track B contract

APS SUPPLY & DEMAND BALANCE
Year 2008
Case 2 (without PWEC Units)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
A.	LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	4,590	4,401	3,939	4,535	5,736	6,402	7,064	7,064	6,389	5,305	3,973	4,589
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	570	548	434	506	593	839	939	939	837	655	495	569
3	TOTAL LOAD REQUIREMENTS	5,160	4,949	4,373	5,041	6,328	7,241	8,003	8,003	7,226	5,960	4,468	5,158
B.	EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(331)	(444)	(604)	(643)	(170)	0	0	0	0	0	(100)	0
7	TOTAL	3,810	3,697	3,451	3,412	3,885	4,001	4,001	4,001	4,001	4,055	4,041	4,141
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	318	318	318	318	318	326	326	326	326	326	326	326
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	22	22	22	22	22	22	22	22	22	22	22	22
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(78)	(78)	402	402	882	890	890	890	890	(70)	(70)	(70)
14	TOTAL EXISTING RESOURCES	3,732	3,619	3,853	3,814	4,767	4,891	4,891	4,891	4,891	3,985	3,971	4,071
C.	EXISTING RESOURCES OVER / (UNDER)	(1,429)	(1,330)	(520)	(1,227)	(1,561)	(2,350)	(3,112)	(3,112)	(2,335)	(1,975)	(497)	(1,088)
D.	FUTURE RESOURCES												
15	WEST PHOENIX CC 4												
16	WEST PHOENIX CC 5												
17	REDHAWK 1-2												
18	SAGUARO SC												
19	TOTAL	0	0	0	0	0	0	0	0	0	0	0	0
20	TOTAL EXISTING EXISTING AND NEW RESOURCES	3,732	3,619	3,853	3,814	4,767	4,891	4,891	4,891	4,891	3,985	3,971	4,071
E.	ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	(1,429)	(1,330)	(520)	(1,227)	(1,561)	(2,350)	(3,112)	(3,112)	(2,335)	(1,975)	(497)	(1,088)

Note: Case 2 has PWEC Track B contract

APS SUPPLY & DEMAND BALANCE
Year 2009
Case 2 (without PWEC Units)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	4,780	4,583	4,102	4,722	5,973	6,667	7,357	7,357	6,653	5,524	4,137	4,779
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	592	568	453	528	620	878	981	981	876	680	514	591
3	TOTAL LOAD REQUIREMENTS	5,372	5,152	4,555	5,250	6,593	7,544	8,338	8,338	7,529	6,205	4,651	5,370
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(193)	(325)	(260)	(649)	0	0	0	0	0	0	(358)	0
7	TOTAL	3,948	3,816	3,795	3,406	4,055	4,001	4,001	4,001	4,001	4,055	3,783	4,141
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	326	326	326	326	326	334	334	334	334	334	334	334
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	22	22	22	22	22	22	22	22	22	22	22	22
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(70)	(70)	410	410	890	898	898	898	898	(62)	(62)	(62)
14	TOTAL EXISTING RESOURCES	3,878	3,746	4,205	3,816	4,945	4,899	4,899	4,899	4,899	3,993	3,721	4,079
	C. EXISTING RESOURCES OVER / (UNDER)	(1,494)	(1,406)	(350)	(1,434)	(1,648)	(2,646)	(3,439)	(3,439)	(2,630)	(2,212)	(930)	(1,291)
	D. FUTURE RESOURCES												
15	WEST PHOENIX CC 4												
16	WEST PHOENIX CC 5												
17	REDHAWK 1-2												
18	SAGUARO SC												
19	TOTAL	0	0	0	0	0	0	0	0	0	0	0	0
20	TOTAL EXISTING EXISTING AND NEW RESOURCES	3,878	3,746	4,205	3,816	4,945	4,899	4,899	4,899	4,899	3,993	3,721	4,079
	E. ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	(1,494)	(1,406)	(350)	(1,434)	(1,648)	(2,646)	(3,439)	(3,439)	(2,630)	(2,212)	(930)	(1,291)

Note: Case 2 has PWEC Track B contract

APS SUPPLY & DEMAND BALANCE
Year 2010
Case 2 (without PWEC Units)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	A. LOAD REQUIREMENTS												
	SYSTEM DEMAND												
1	PEAK DEMAND	4,982	4,776	4,275	4,921	6,225	6,948	7,667	7,667	6,934	5,757	4,312	4,981
	RELIABILITY												
2	RESERVE REQUIREMENTS 15% SUMMER, 12% NON-SUMMER	615	591	473	550	649	919	1,027	1,027	917	707	534	614
3	TOTAL LOAD REQUIREMENTS	5,597	5,367	4,748	5,472	6,874	7,867	8,694	8,694	7,850	6,464	4,846	5,595
	B. EXISTING GENERATION & PURCHASED POWER RESOURCES												
	EXISTING GENERATION RESOURCES												
4	APS EXISTING GENERATION	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055	4,055
5	SEASONAL VARIATION	86	86	0	0	0	(54)	(54)	(54)	(54)	0	86	86
6	CAPACITY ON MAINTENANCE	(199)	(414)	(411)	(643)	(170)	0	0	0	0	0	(210)	(210)
7	TOTAL	3,942	3,727	3,644	3,412	3,885	4,001	4,001	4,001	4,001	4,055	3,931	3,931
	PURCHASED POWER RESOURCES												
8	SRP - FIRM	334	334	334	334	334	342	342	342	342	342	342	342
9	SRP - CONTINGENT	62	62	62	62	62	62	62	62	62	62	62	62
10	ENVIRONMENTAL PORTFOLIO	23	23	23	23	23	23	23	23	23	23	23	23
11	PACIFICORP DIV EXCH	(480)	(480)	0	0	480	480	480	480	480	(480)	(480)	(480)
12	APS CURRENT SYSTEM POSITION	0	0	0	0	0	0	0	0	0	0	0	0
13	TOTAL PURCHASES	(61)	(61)	419	419	899	907	907	907	907	(53)	(53)	(53)
14	TOTAL EXISTING RESOURCES	3,881	3,666	4,063	3,831	4,784	4,908	4,908	4,908	4,908	4,002	3,878	3,878
	C. EXISTING RESOURCES OVER / (UNDER)	(1,716)	(1,701)	(685)	(1,641)	(2,090)	(2,959)	(3,786)	(3,786)	(2,943)	(2,463)	(968)	(1,717)
	D. FUTURE RESOURCES												
15	WEST PHOENIX CC 4												
16	WEST PHOENIX CC 5												
17	REDHAWK 1-2												
18	SAGUARO SC												
19	TOTAL	0	0	0	0	0	0	0	0	0	0	0	0
20	TOTAL EXISTING EXISTING AND NEW RESOURCES	3,881	3,666	4,063	3,831	4,784	4,908	4,908	4,908	4,908	4,002	3,878	3,878
	E. ADDITIONAL RESOURCE (DEFICIT) / SURPLUS	(1,716)	(1,701)	(685)	(1,641)	(2,090)	(2,959)	(3,786)	(3,786)	(2,943)	(2,463)	(968)	(1,717)

Note: Case 2 has PWEC Track B contract

APS-7R

EXHIBIT
APS-7R
admitted

REBUTTAL TESTIMONY OF

EDWARD Z. FOX

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

Table of Contents

REBUTTAL TESTIMONY OF EDWARD Z. FOX
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. <u>INTRODUCTION.</u>

Q. PLEASE STATE YOUR NAME.

A. Edward Z. Fox.

Q. WHAT IS YOUR POSITION AND WHAT ARE YOUR RESPONSIBILITIES AT APS?

A. I am Vice President of Communications, Environment and Safety for Arizona Public Service Company ("APS" or "Company"). In that capacity, I am responsible for environmental, health and safety compliance and policy, as well as corporate communications and communications-related policies. I also oversee the technology development programs that identify and help develop new technologies such as solar energy and fuel cells and which implement other programs such as the Environmental Portfolio Standard ("EPS"). I also provide policy input for other societal and environmentally-related programs such as demand side management ("DSM"). A summary of my qualifications and background is attached as Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the testimony of various Arizona Corporation Commission ("Commission ") Staff and intervenor witnesses relating to the EPS, renewable resources, DSM, communications and advertising. I respond to testimony from Staff witness Barbara Keene, RUCO witness Marylee Diaz Cortez, and Western Resource Advocates' ("WRA") witness Dr. David Berry regarding their proposals and associated funding of the EPS and other renewable resource issues. From a policy perspective, I address the recommendations and proposals of Staff and several intervenors regarding DSM programs, including those of Southwest Energy Efficiency Project ("SWEEP") and RUCO to dramatically increase spending on DSM programs, as well as the proposal by the Arizona Community Action Alliance ("ACAA") for the Company to increase marketing of the E-3 low income rate discount program. I also respond to the questions from Commissioner Hatch-Miller regarding DSM and the EPS in his letter of November 17, 2003. APS witness Thomas A. Hines addresses specific proposals and DSM policies in his rebuttal testimony. Finally, I oppose Staff's recommended disallowances for advertising expenses and the implication that it may have been inappropriate for APS to obtain air permits at West Phoenix and Saguaro for Pinnacle West Energy Corporation ("PWEC").

II. SUMMARY OF TESTIMONY.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Staff and the other parties that commented on the EPS recognize that current funding levels are inadequate to meet the renewable resource requirements of 1.1 percent of APS' retail energy by 2007 given the current required technology mix. Although some parties propose higher funding for the EPS, none have advocated increasing the funding to the level necessary to meet the current EPS goals. To actually achieve the goals of the current EPS in 2007 would require EPS funding for APS to increase by roughly $80 million or more per year. However, due to fact that such increased funding would be coming so close to 2007, it still would be impractical to reasonably acquire and install solar capacity at the rate necessary to meet the solar portion of the standard by that date.

The EPS, however, is being addressed in workshops sponsored by the Commission this year, and those workshops could result in changes that may reduce the cost of compliance. For example, allowing increased use of lower-cost Arizona renewable resources such as wind or biomass could allow the EPS to be achieved more quickly and with lower funding than a more solar-intensive portfolio. Because of the possibility of such program changes, APS recommends that the Commission establish an adjustment mechanism for the EPS that collects the level of funding that will allow timely compliance with the EPS, but which can be adjusted to reflect the potential for lower program costs if the Commission elects to change the EPS goals, resource mix or schedule. APS witness David Rumolo addresses the proposed mechanism in his testimony.

APS disagrees with Dr. Berry of the WRA that the Commission should require the Company to obtain two percent of its energy from wind capacity within the next two years in addition to the EPS. Such a mandate would require customers to pay a premium over other resources and, because of the limited amount of proven wind resources in Arizona, most of the money for the program would by necessity flow to existing out-of-state wind projects. I believe that Dr. Berry's recommendation for wind hedging, as well as his suggestion that the EPS be expanded and that a net metering plan be implemented, should be considered outside this rate case in a generic docket.

Several parties recommended significantly expanding the Company's DSM programs. APS agrees that building upon some of our already more successful market transformation programs would be beneficial. As a result, APS proposes to increase and expand its DSM programs as described in APS witness Thomas Hines rebuttal testimony. The biggest difference on DSM issues between APS and parties such as RUCO and SWEEP is the appropriate program approach and the required level of funding to achieve the right "bang for the buck." APS believes that a reasonable, bottom-up, program-driven approach is the most effective way to expand DSM. Using the Company's own experience with DSM in Arizona, and drawing on DSM strategies that are proving to be successful in Arizona and other states, I believe that APS can implement appropriate and cost-effective DSM strategies for roughly $3 million per year. This is generally consistent with Staff's recommendation of a $4 million ceiling for DSM expenditures. However, the $30 million-plus recommendations of SWEEP and RUCO are extravagant in scope, unwarranted by APS' situation as compared to other utilities implementing larger programs, and would not be cost-effective.

APS also supports ACAA witness Brian Babiars' proposal to increase marketing for low income outreach programs, and I propose to increase funding for such outreach programs.

Staff witness James Dittmer recommends disallowing certain customer communication expenses that he deems inappropriate "image building" and which he claims do not otherwise benefit customers. Contrary to Mr. Dittmer's assertions, APS' communication programs were effective and beneficial to customers by letting them know that APS (and Arizona) were not succumbing to the problems faced by utilities in other states during some of the most tumultuous times for the electric utility industry in memory. Informing APS customers about the status of electric service reliability and allying their concerns is a reasonable and prudent expense that should be fully recovered.

Finally, in her analysis of the circumstances surrounding the application for an air permit for PWEC's West Phoenix 4-5 and Saguaro units, Staff witness Linda Jaress failed to note that state and federal laws relating to air permits required APS to apply for the permits, because the PWEC and APS plants were under common corporate control. She thus left the impression that APS was somehow inappropriately favoring PWEC in performing this legally-required service.

III. <u>EPS AND RENEWABLE RESOURCES.</u>

A. EPS

Q. HAVE YOU REVIEWED THE TESTIMONY OF STAFF AND INTERVENORS ADDRESSING THE EPS?

A. Yes.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF THAT TESTIMONY?

A. It appears that all parties that commented on the EPS recognize that the current funding levels are not sufficient to meet the renewable energy goals in the EPS. Staff and the WRA have both suggested modifications to the EPS funding, such as removing the current per-customer caps for the EPS surcharge. RUCO recommends that the EPS be funded solely through the EPS surcharge "at what is ultimately determined to be an adequate level." (M. Diaz Cortez Test. at p. 26.) However, RUCO also recommends shifting to DSM spending the roughly $6 million in APS' base rates that currently supplements EPS surcharge collections. This recommendation, of course, would reduce funds that are used for the EPS, making the shortfall of EPS funding all the more acute.

Q. DO YOU AGREE WITH THESE RECOMMENDATIONS REGARDING THE EPS?

A. I agree that increasing the funding for the EPS will help APS make some further progress towards meeting the EPS's renewable energy goals. But neither Staff, RUCO, nor the WRA actually propose in their testimony that the program be sufficiently funded to allow APS to meet the current EPS goals. If APS is to meet the EPS's renewable energy standards, the Commission needs to approve adequate funding <u>or</u> modify the EPS program in a way that makes the authorized funding sufficient to allow compliance. For example, as APS suggested in the EPS workshop in March, by allowing utilities to pursue the 1.1% goal in 2007 with increased use of other in-state lower-cost renewable resources, like biomass or wind, significant additional funding may not be required. Such a modification could likely achieve the 1.1% goal and continue with significant funding of solar resources, including distributed applications. Additionally, this could facilitate achieving a renewable resources portfolio standard higher than 1.1% after 2007, and provide for increased emphasis on funding for solar resources. Ultimately, the 60% solar goal would be met, but in a timeframe after 2007 when the technology is more cost-effective.

Q. WHY DOES THE PROGRAM FUNDING HAVE TO BE INCREASED INSTEAD OF SIMPLY REQUIRING APS TO MEET THE STANDARD, EVEN IF THAT MEANS THAT SHAREHOLDERS HAVE TO FUND THE PROGRAM?

A. As a rate regulated public service corporation, APS' rates are established through traditional principles of cost-of-service ratemaking. This means that APS is entitled to a fair return on investment and recovery of reasonably incurred expenses. If the Commission requires APS to procure a certain level of renewable resources when serving customers, the Commission must include the costs of those resources when establishing APS' rates, just like it provides for the cost of traditional generation resources or purchased power expenses. In some states with an environmental portfolio standard, like Nevada and California, the state commission "funds" utility programs by approving contracts between the utility and a renewable resource supplier, and providing for cost recovery in the utility's rates through already existing rate adjustment mechanisms. In other states, including Arizona, a different mechanism was adopted where a separate customer surcharge provides funding for the program. Some states use a combination of both approaches. In any case, the costs necessary to comply with the program have to be included somewhere in the utility's rate structure. This has certainly been understood since the inception of the EPS, when the Commission expressly stated, "It is the intent of this Rule that the surcharge will cover the cost of the mandate." See Decision No. 63364 (February 8, 2001) at 4.

Q. DOES APS SUPPORT THE INCREASED USE OF RENEWABLE RESOURCES?

A. Yes. I strongly believe that any policy differences between the Company and advocates of increased use of renewable resources center around the question of "how" and "how fast" rather than "whether." APS recognized early on that solar energy would be a significant part of our future. That was one reason that APS was the first utility in Arizona (and one of the first in the United States) to offer a solar energy purchase program—our APS Solar Partners program. That program has both commercial and residential options, allowing customers to direct a portion of their electric bill to support solar energy. We also developed the Solar Technology and Research ("STAR") Center in Tempe, Arizona which is one of the premier solar testing and research facilities in the world and the only utility-owned center of its kind in the United States. And our commitment is not solely facilities-based. APS developed Project SOL (Solar Outreach and Learning) which takes real-time data from solar energy facilities and makes it available through the Internet to students and teachers. This program fosters awareness of solar energy in the educational community and, most importantly, in our youth.

Through the EPS program, APS is deploying solar technologies as fast or faster and with greater diversity than any other utility in the United States. APS has installed nearly five megawatts of solar generation, and we are breaking ground on a 1 MW solar trough system, which is the first new solar thermal trough project in the world in over a decade. We operate the largest Concentrating Photovoltaic

("CPV") power plant in the world, which totaled over 500 kWac at the end of 2003. With rapid advances being seen in CPV, this technology has the potential for low-cost, large-scale use in the near future. We helped develop a very efficient tracking design for photovoltaic systems that helps produce 15-50 percent more energy from photovoltaic modules, making these systems more cost-effective, and we continue to improve on this design. We continue to support many off-grid solar customers, and have implemented the first off-grid utility solar lease service to replace a commercial customer's diesel system. These accomplishments demonstrate the value of the EPS program in driving down costs of solar technologies and making this energy resource more affordable over the long-term. The Company also offers the most aggressive buy-down program in the state to help leverage EPS funding with additional customer dollars, and we have focused on using Arizona companies for solar installations, engineering, controls and electronics, including an inverter company that has chosen to locate an office in Arizona.

Q. HAVE APS' RENEWABLE ENERGY EFFORTS BEEN FOCUSED EXCLUSIVELY ON SOLAR TECHNOLOGIES?

A. No. While solar energy is a key component of our overall renewable energy plan, APS is also developing other renewable resource technologies such as biomass, biogas, geothermal and wind. These non-solar renewable resources are generally more mature technologies and so are less expensive than solar technologies. I also think that some of these technologies are as natural a "fit" for Arizona as solar. For example, the bark beetle infestation and recent fires have caused major damage to our forests and generated a tremendous amount of wood wastes as forests need to be thinned of trees to control future fires. APS has facilitated the construction of a new biomass power plant to combust this wood waste and generate electricity. APS is also contracting to purchase as much as 15 MW of biogas generation from a large wastewater treatment plant in Phoenix, Arizona. APS is also the only utility in Arizona actively pursuing in-state geothermal resources. And, we are investigating and pursuing opportunities for developing wind generation in the state. APS recently contracted for 15 MW of wind generation from a wind farm being developed near St. Johns, Arizona, which will cost-effectively satisfy a major portion of APS' non-solar EPS requirements. Finally, APS has been nationally recognized for its social and environmental leadership, including renewable energy and DSM, by Innovest. Innovest is an international research and advisory firm that analyzes corporate performance on social, environmental and governance issues.

Q. **WHAT IS THE CURRENT EPS GOAL?**

A. The Commission this year approved an increase to the EPS, establishing a target of procuring 1.1 percent of APS' total retail energy supply from renewable energy resources by 2007. Of that, 60 percent must be from solar resources and 40 percent can be from non-solar renewable generation located in Arizona. In addition, solar resources may receive extra credit multipliers to further encourage the use of solar technology, and systems installed since 1997 were also allowed to be included.

Q. **BASED ON THE CURRENT EPS GOAL AND EXISTING PROGRAM RESTRICTIONS, WHAT WOULD IT COST APS TO MEET THIS REQUIREMENT BY 2007?**

A. To reach the 1.1 percent renewable energy goal, assuming the current restrictions on resource mix and in-state requirements, APS would have to build nearly 40 MW of solar generation capacity by the end of 2006 and take full advantage of the multipliers allowed under the EPS for solar installations. The total cost for this construction would be a cumulative figure of approximately $180 million by the end of 2006 for the solar component alone. But, as I will discuss, such an amount could not be reasonably deployed in the time remaining before 2007.

Q. ARE YOU RECOMMENDING THAT THE COMMISSION INCREASE FUNDING TO THE AMOUNT NECESSARY TO MEET THE CURRENT EPS GOALS?

A. If the Commission intends to require APS to meet the current goals, the EPS program needs to be funded. However, increasing EPS funding an additional $80 million per year for two years is clearly not the best option. For one thing, it would be virtually impossible to deploy that increased level of funding by 2007 in a prudent and cost-effective manner. It would likely result in the construction of a single massive solar trough facility, preventing the use of EPS funds to drive down costs for other solar technologies and the development of a diverse mix of solar resources. Even pursuing only a single central station project, the development of these levels of solar capacity typically requires several years to ensure that the proper technology is selected, sited correctly, and interconnected to the transmission system. I do not believe that it would be at all practicable to complete the installation of this much solar capacity by the end of 2006, even if the technology were immediately available once funding was approved. Also, because the cost of solar capacity continues to decline, front-loading the spending could result in significantly less solar capacity being constructed than if the same dollars were spread over a longer period of time.

I believe that there are more cost-effective ways to modify the EPS program and do not advocate setting EPS funding at the maximum level that APS can spend unless the Commission intends to require APS to meet the EPS goals as soon as possible. Schedule EZF-1RB shows how these funding requirements have been calculated and the assumptions used to develop them. Mr. Rumolo has used this figure in his design of APS' proposed adjustment mechanism.

Q. IF STAFF'S AND WRA'S RECOMMENDATIONS ARE ACCEPTED, AND THE EPS SURCHARGE REMAINS $0.000875/KWH BUT THE PER-CUSTOMER CAPS ARE REMOVED, WILL THE FUNDING BE SUFFICIENT TO ALLOW APS TO MEET THE EPS GOALS?

A. No. The EPS rule currently caps the amount of the EPS surcharge that can come from a particular customer, and the amount varies by customer class. Schedule EZF-2RB shows the effect of removing the customer caps but leaving the surcharge amount at 0.875 mills. Removing the caps would increase funding from the EPS surcharge to an estimated $22 million per year. But, many APS customers are already below the caps so this would still not provide enough necessary funding. This means that the Company would only reach about 21 percent of the overall EPS energy goals by the end of 2007 if the per-customer caps are removed.

Q. WOULD THE OTHER RECOMMENDATIONS OF MS. KEENE, SUCH AS EXPANDING THE BUY-DOWN PROGRAM AND PURSUING MORE LARGE-SCALE SOLAR THERMAL PROJECTS, REDUCE THE COST TO COMPLY WITH THE EPS?

A. APS has been implementing, and will continue to implement, programs that align with the recommendations of Ms. Keene. While all of these steps help make progress towards the EPS goals, they cannot compensate for the lack of adequate funding because they do not sufficiently affect the cost to comply with the EPS goals. For example, the Company has increased the amount offered to customers through its buy-down program. But customer buy-down programs lack the volume or project size to significantly reduce the cost to achieve an aggressive portfolio of mostly solar generation. These programs also depend on customers affirmatively opting in, making it more difficult to forecast the system-wide impact of a buy-down program. Similarly, APS enters into renewable contracts with third parties, but these contracts require a balanced consideration of factors such as financing costs and O&M that cause project costs to increase above the cost of directly constructed new capacity. As a result of these higher costs, third party contracts may offer some short term benefits but at higher costs over the life of a project.

Q. WHAT LEVEL OF EPS COMPLIANCE WILL BE REACHED USING THE EXISTING FUNDING, RESOURCE MIX, AND OTHER REQUIREMENTS OF THE EPS?

A. APS has commitments for sufficient EPS energy to meet the non-solar resources goal in 2007. Beginning in 2007, more EPS funding would be committed to solar. Under this schedule, 3 to 6 MW of solar installations per year would be funded. By the end of 2007, APS will meet 100 percent of the non-solar resources goal and about 13 percent of the solar resources goal. Schedule EZF-3RB shows how the EPS program would be implemented by APS assuming existing funding levels and program restrictions continue.

Q. GIVEN CURRENT FUNDING LEVELS AND EPS PROGRAM RESTRICTIONS, WILL APS EVER MEET THE EPS GOALS?

A. Our current projections show APS meeting the 1.1 percent EPS renewable energy goal in about 2018, assuming that the standard remains at 60 percent solar and 40 percent non-solar.

Q. WHAT HAPPENS IF THE EPS FUNDING IS REDUCED AS PROPOSED BY SWEEP AND PERHAPS BY RUCO?

A. RUCO and SWEEP propose redirecting $6 million that is currently used for EPS funding to new DSM spending. This would reduce EPS funds available to APS by almost 50 percent. The net result of such a reduction would be that the EPS, as currently structured, would take almost twice as long to achieve, even assuming forecasted price reductions for future technologies. The Company believes that it would be more appropriate to put separate mechanisms in place for both DSM and the EPS to address funding.

Q. DOES THE INABILITY TO MEET THE EPS ON SCHEDULE MEAN THAT APS HAS FAILED TO WISELY MANAGE THE FUNDING IT RECEIVED?

A. Absolutely not. It means that the funding was not sufficient to achieve the EPS goals. This was recognized by the CEWG, and this is also something that APS has expressed as a major concern since the program was first adopted. I agree with the CEWG's conclusion in its 2003 Report that "TEP and APS have acted carefully in the selection, design, installation, and operation of their renewable generation resources, and have reasonably managed EPS financial resources." (See CEWG Final Report at p. 48.)

Q. ARE THERE PROCEEDINGS AT THE COMMISSION THAT MAY AFFECT THE STRUCTURE OF THE EPS PROGRAM?

A. Yes. As I mentioned earlier, the Commission has commenced a series of workshops to address the structure of the EPS. It is my understanding that these workshops will explore things such as the resource mix of the EPS, whether additional technologies should be included in the EPS, and what funding is available to achieve the EPS. APS has been, and will continue to be, active in these workshops.

Q. COULD THESE WORKSHOPS AFFECT THE ANALYSIS IN YOUR TESTIMONY REGARDING COMPLIANCE WITH THE EPS?

A. The costs for APS to comply with the EPS depend significantly on the structure of the EPS. For example, if the current requirement that 60 percent of the EPS energy has to come from solar technologies is reduced, APS could look to lower-cost renewable resources, such as wind or biomass or landfill gas, to meet the EPS. This is similar to the recently adopted renewable resources program in New Mexico which initially established a 5 percent standard but without any technology requirements. If APS is allowed to increase its use of such lower-cost renewable resources within the EPS, the costs and timing required to achieve the

EPS goals would certainly decrease. The specifics depend on how (or whether) the EPS is modified at the workshops and APS is discussing options in those workshops that it believes are appropriate improvements to the EPS.

Q. GIVEN THE ANALYSIS OF THE EPS IN THE WORKSHOPS, HOW SHOULD THE COMMISSION ADDRESS THE EPS IN THE COMPANY'S RATE CASE?

A. The Commission should match developments relating to the EPS in the workshops with the ultimate outcome of the Company's rate case. The cleanest way to address funding for a program such as the EPS is within a rate case, and that has traditionally been the approach chosen by the Commission. For example, the predecessor to the EPS was the Energy Efficiency and Solar Energy ("EEASE") Fund, which was established in APS' 1991 rate settlement. Such an approach ensures that the Commission can consider the funding for a program such as the EPS in concert with other general funding requirements and other special programs, such as the DSM programs that several parties have proposed in this case. Moreover, at least one party to these proceedings (RUCO) had indicated that it would continue to oppose any attempt to increase EPS funding except in a general rate case.

Q. DOES APS HAVE A SPECIFIC PROPOSAL FOR AN EPS FUNDING MECHANISM TO BE ADOPTED IN THIS RATE CASE?

A. Yes. I agree in principle with Ms. Keene's approach that a surcharge continue to be used for EPS funding, although APS is proposing some modifications to Staff's surcharge proposal. The most important requirement for any funding mechanism, given the potential for changes to program scope and costs as a result of the current (or future) EPS workshops, is the flexibility to adjust funding levels. For example, to achieve the current EPS, assuming that the equipment could be delivered and installed in a timely way, would require an additional $80 million per year in 2005 and 2006. If the EPS resource mix and timing is changed in a way that reduces necessary funding to, for example, $15 million in a given year, the funding mechanism chosen should be able to reflect that change as quickly as practicable. An EPS surcharge collected from all distribution customers with a ceiling on the total annual funding level, as opposed to the per-customer caps in the current EPS surcharge, provides that flexibility.

Q. COULD YOU EXPLAIN IN MORE DETAIL HOW APS' PROPOSED SURCHARGE DIFFERS FROM STAFF'S PROPOSED SURCHARGE?

A. The primary difference is that APS' proposed EPS surcharge asks the Commission to determine a maximum annual amount to fund the EPS program, rather than adopting a specific per kWh charge. APS' proposed EPS surcharge would be established to initially collect that maximum amount, but could be adjusted lower based on potential Commission policy or rule changes to the program or a decline in cost estimates to meet the goals. By using a total program funding level, rather than a cents per kWh charge (with or without individual customer caps), there is more flexibility to address changes in the funding requirements. This type of surcharge is very similar to the EEASE Fund surcharge approved for APS by the Commission in 1994. Mr. Rumolo discusses the specific rate design and administration of APS' proposed EPS surcharge in more detail in his rebuttal testimony.

Q. WOULD THIS TYPE OF SURCHARGE ALLOW APS TO MEET THE EPS GOALS?

A. It could. The type of surcharge proposed by APS would certainly go further than the current EPS surcharge, whether with or without the per-customer caps. The Commission could establish a ceiling for APS' proposed EPS surcharge in an amount sufficient to permit compliance with the EPS. Then, if the costs to comply with the EPS come down more than expected, or if the program is restructured in a way that lowers the compliance costs for APS, the surcharge amount could be reduced. Of course, the current EPS goal reaches 1.1 percent of energy in 2007 while the proposed EPS surcharge would likely not start generating funds for APS until early 2005. As a result, there may be some lag in deploying the funds collected to appropriate projects. Still, the timeline for achieving the EPS goals could be significantly improved.

Q. IF THE COMMISSION DECIDES TO LEAVE THE CURRENT EPS FUNDING LEVELS FOR APS UNCHANGED IN THIS RATE CASE IS THERE ANY NEED FOR APS' PROPOSED EPS ADJUSTMENT MECHANISM?

A. Yes. I believe that even if the EPS funding levels remain unchanged in this rate case, it is critical that the Commission adopt a more flexible EPS funding mechanism for APS. The current mechanism, which consists of a fixed per-kWh charge, does not allow for changes in EPS funding if there are changes in technology costs or EPS policies. In fact, one of the key problems with the original EPS was the concern, since proven to be true, that the funding provided through the original EPS surcharge was inadequate. This concern has caused uncertainty to cloud the EPS which can be avoided by a more flexible adjustment mechanism. Thus, even if the Commission elects to leave current EPS funding levels unchanged, it should take this opportunity to adopt the more flexible mechanism proposed by APS witness David Rumolo either in lieu of or as a complement to the existing EPS surcharge.

B. NET METERING

Q. DO YOU AGREE WITH DR. BERRY'S RECOMMENDATION THAT APS' SCHEDULE EPR-4 SHOULD BE CHANGED?

A. No. The EPR-4 and EPR-2 rate schedules that Dr. Berry addresses are net billing programs that support customer installations and allow customers with qualifying renewable energy facilities to sell energy from these systems back to APS. If a rate schedule is developed to provide additional financial assistance or incentives to customers that install renewable systems, as suggested by Dr. Berry, APS would recommend that a separate schedule be developed outside of the rate case on a pilot basis. This separate pilot program would provide maximum flexibility to the Commission and APS to monitor its impact, gauge its success, and determine the appropriate level of benefits to all our customers.

Q. WHY IS THE DEVELOPMENT OF A NET METERING PROGRAM OUTSIDE OF THE RATE CASE APPROPRIATE?

A. I would note initially that APS has been discussing a net metering proposal with several other parties and Staff, and intends to continue that dialogue. A properly crafted net metering plan needs to be both reasonable for the utility and the interconnecting customer, and equitable to other customers of APS. For example, one critical question that would need to be addressed is the appropriate funding structure for a net metering program to ensure that our customer base is not required to inappropriately subsidize the costs of a net metered customer. These policy issues are best worked out in separate workshops and similar forums, and implemented initially through a pilot program.

C. WRA'S RECOMMENDATIONS ON OTHER RENEWABLE RESOURCES ISSUES

Q. WRA WITNESS BERRY RECOMMENDS THAT THE COMMISSION ORDER APS TO ACQUIRE 2 PERCENT OF ITS ENERGY FROM WIND GENERATION WITHIN TWO YEARS. DO YOU BELIEVE THIS IS APPROPRIATE?

A. No. I agree that wind generation is a promising and low cost renewable resource, and note that APS is pursing a 15 MW wind project in Northern Arizona. I disagree with Dr. Berry's proposal, however, because it does not represent an effective use of funds collected from Arizona customers. APS witness Peter Ewen responds in his rebuttal testimony to Dr. Berry's argument that wind generation can act as an effective hedge against natural gas price volatility.

Q. WHY ISN'T DR. BERRY'S WIND PROPOSAL A REASONABLE USE OF FUNDS COLLECTED FROM ARIZONA CUSTOMERS?

A. Dr. Berry argues that the funding required to implement his proposed wind generation experiment should be recovered through a purchased power adjustment mechanism. Although such funding will be less expensive than solar generation, it will be higher than natural gas capacity and thus will require APS customers to pay a premium for the wind generation acquired under his proposal. Dr. Berry's "two percent" proposal would require the construction of roughly 200 MW of wind generation for APS. Because there are relatively limited opportunities to construct effective large-scale wind capacity in Arizona (compared to the 200 MW requirement implicit in WRA's proposal), and because it will take considerable time to develop Arizona wind resources after they are proven, most of the new wind generation in Dr. Berry's proposal would have to be sited out of state. That means that the cost paid by Arizona customers for this generation would flow out of Arizona and the energy would come from outside Arizona, which would be contrary to one of the EPS' goals. I strongly support the EPS' focus on in-state technology development and construction as being the more appropriate way to use funds collected from our customers. I also believe that Dr. Berry should present his recommendations for increased use of wind capacity in a generic proceeding, such as the EPS docket, rather than company by company through rate cases, where the opportunities for participation by interested parties are more limited. As a result, I do not believe that Dr. Berry's recommendation should be forced on the Company in this case.

Q. DO YOU SUPPORT DR. BERRY'S PROPOSAL TO INCREASE THE EPS?

A. While we disagree on the amount of the increase, I support consideration of the EPS goals in the workshops that the Commission is sponsoring. I also agree with Dr. Berry that it should be done in a separate generic docket rather than in this rate case.

IV. DEMAND SIDE MANAGEMENT TESTIMONY

A. INTRODUCTION

Q. WHAT RECOMMENDATIONS HAVE OTHER PARTIES TO THIS PROCEEDING MADE CONCERNING THE COMPANY'S EXPENDITURES FOR DSM PROGRAMS?

A. In Staff witness Barbara Keene's direct testimony, Staff does not recommend any specific DSM programs, but recommends that the Company expand its current DSM spending to an annual cap of $4 million. This is approximately four times the $1.1 million of DSM expenditures during the test year. Staff also recommends that these funds be recovered through a DSM adjustment mechanism for programs that are pre-approved by Staff.

RUCO witness Marylee Diaz Cortez also does not propose any specific DSM programs, but advocates a major expansion in DSM spending to a total annual level of $35 million, including a reassignment to DSM of $6 million that currently supplements the EPS surcharge. RUCO also recommends that DSM programs be pre-approved and reviewed annually by Staff. Further, RUCO recommends that each year any unspent funds roll over to a balancing account to be used in subsequent years. Any account balance at the time of a rate case would not be eligible for future recovery.

SWEEP witness Jeffrey Schlegel recommends a greatly expanded DSM program for APS. SWEEP's proposal is purportedly designed to achieve a 7 percent reduction in total energy resources needed to meet retail load in 2010 and 17 percent in 2020. This recommended program will require funding of approximately $13 million in 2004, $30 million in 2005 and increased amounts thereafter (for example, $41 million in 2006 and $50 million in 2014). SWEEP calculates that the funding will require a charge of $0.0015 per kWh of retail sales. Like RUCO, SWEEP also recommends a balancing account for unspent funds.

Q. DO YOU AGREE WITH THE RECOMMENDATIONS CONCERNING DSM MADE BY OTHER PARTIES?

A. APS agrees with Staff, RUCO and SWEEP that a reasonably expanded DSM program can provide customer benefits and help the Company cost-effectively manage both overall customer growth and growth in peak demand, and provide additional opportunities for customers to better manage their energy costs. APS also agrees that the allowed funding should match the required expenditures for a total DSM program, and that Staff should continue their review and pre-approval of specific DSM programs and their review of annual expenditures. The Company also believes that some of the specific program ideas and concepts from the SWEEP proposal warrant further consideration and analysis.

The most significant difference between the proposals of Staff, RUCO and SWEEP is the proposed size of the DSM program and the commensurate level of cost to APS customers. Staff's recommendation is the most appropriate of the three, given the current funding for DSM and the circumstances presented both in Arizona and APS' service territory. Staff's proposal restores annual funding to a level that is somewhat higher than, but generally consistent with, annual expenditures prior to 1999—the year that most DSM funds were shifted to renewables. APS also agrees with Staff that an adjustment mechanism is appropriate to fund expanded DSM programs, although the Company would propose establishing a higher ceiling for the adjustment mechanism than Staff but an initial funding level that is generally consistent with Mr. Keene's proposal. The Company's specific program-based proposal for an expanded DSM program is discussed in more detail later in my testimony and in the testimony of APS witness Thomas A. Hines.

On the other hand, RUCO's and SWEEP's proposals for $30 million to $50 million per year for DSM are too large to cost-effectively implement and represent dramatic increases in DSM expenditures compared with both present and past levels. These proposals are too extreme and too costly given current circumstances and are not grounded by sufficient data. RUCO, for example, does not provide any evidence to show that their recommendation of a $35 million increase is either appropriate or feasible, let alone whether it would provide sufficient customer benefits to warrant that level of spending. RUCO also does not provide any detail on the types of programs, objectives, achievements and, most importantly, potential customer benefits associated with their proposal. Although SWEEP provides more detail than RUCO for their recommended DSM program, much of the information is based on regional data that may not be applicable either to Arizona or APS' service territory. SWEEP's analysis certainly does not justify the roughly ten-fold increase from the highest levels of historical DSM spending that it proposes.

B. DSM PROGRAM BACKGROUND AND EXPENDITURES

Q. HAS THE COMMISSION REQUIRED CHANGES TO THE FUNDING LEVELS FOR DSM SINCE THE COMPANY'S LAST RATE CASE?

A. Yes. In Decision No. 59601 (April 24, 1996) the Commission allowed $7 million to be recovered for DSM and renewables through a "system benefits charge," with at least $3 million to be expended per year for each program. In Decision 62506

(May 4, 2000), which initially approved the EPS, the Commission ordered the Company to shift $3 million of the DSM funding in the system benefits charge to the EPS program, leaving $1 million for low income and other DSM programs. In Decision 63364 (Feb. 8, 2001), the Commission approved the current EPS surcharge which provided for a limited amount of additional funding to meet the newly-established EPS.

Q. COMMISSIONER HATCH-MILLER ASKED SEVERAL QUESTIONS CONCERNING DSM AND RENEWABLE EXPENDITURES. COULD YOU RESPOND TO THOSE QUESTIONS?

A. Yes. In a letter dated November 17, 2003, Commissioner Hatch-Miller asked the Company to respond to several questions related to DSM and EPS expenditures. Specifically, he asked: (1) How much has APS spent on its Market Transformation Strategy each year since 1996? (2) How much has APS spent on low-income weatherization programs each year since 1996? and (3) How much money has APS moved from the system benefit charge for EPS purposes each year since 1996?

The annual expenditures on market transformation, the Energy Wise program (low income weatherization and bill assistance), and renewables from 1996 to 2003 are provided in Schedule EZF-4RB, attached to my rebuttal testimony. The Company spent on average nearly $3.9 million each year from 1996 to 2000 for DSM, including the Energy Wise program. Annual spending for renewables averaged approximately $3.8 million during this same period. This spending level conforms to the Commission requirements discussed earlier. From 2001 through 2003, the Company reduced system benefits spending for DSM and increased spending on renewables consistent with the Commission's decisions in the EPS docket.

Q. IN ADDITION TO THE CHANGES IN FUNDING FOR DSM, HAS THE COMMISSION ALSO CHANGED THE TYPES OF DSM PROGRAMS THAT THE COMPANY OFFERS?

A. Yes. In Decision 59601 (April 24, 1996), the Commission directed the Company to discontinue the "traditional" DSM programs that offered rebates and other incentives to customers who agreed to implement various energy efficiency measures, such as efficient lighting, motors, HVAC and appliances. Instead, the Commission directed the Company to implement "market transformation" programs, which are aimed at more long-lasting impacts resulting from changing the practices, behavior, and decisions of builders, vendors, and customers. Market transformation programs thus focus more on education, training, and ongoing involvement with these groups. In addition to reducing peak and overall energy consumption, and producing some customer savings, market transformation efforts were thought to be more effective in creating and sustaining market changes related to energy efficiency. Further, these fundamental market changes could result in more persistent reductions in energy use than "traditional" DSM rebate programs. The Commission also expressed a desire that the Company focus on market transformation programs aimed at residential customers, because the belief was that non-residential customers could implement DSM measures through established commercial channels without the Company's assistance and customer funding. Mr. Hines addresses in his rebuttal testimony how APS implemented the Commission's market transformation strategy.

C. ENERGY WISE LOW INCOME ASSISTANCE

Q. DO YOU AGREE WITH MS. KEENE'S RECOMMENDATION CONCERNING THE BILL ASSISTANCE PROGRAM?

A. No. Ms. Keene proposes to separate the funding for low income weatherization and bill assistance. She asserts that weatherization is DSM and therefore should be funded through an adjustment mechanism along with the other DSM programs, but bill assistance is not DSM and should be funded through system benefits (B. Keene Testimony at p. 15). Although conceptually Ms. Keene is correct, the funding for low income weatherization and bill assistance should remain together because both are integral components of the same Energy Wise low income assistance program. They are contracted, funded, and implemented together as part of an overall effort to assist our low income customers. In fact, the Company's bill assistance component is funded proportionally to low income weatherization and other parts of the total Energy Wise program. Thus, if the funding is separated as Ms. Keene proposes, bill assistance would not grow along with the increase in funding for the overall low income weatherization program as proposed by the Company. The combined funding for the Energy Wise program, including weatherization and bill assistance, should be provided together as part of one program and moved from base rates to the SBAC-1 adjustment mechanism along with the funding for the other DSM programs.

Q. MS. KEENE NOTES THAT THE COMPANY HAS UNDERSPENT FUNDS ON THE LOW INCOME WEATHERIZATION PROGRAM. CAN YOU EXPLAIN THAT?

A. Yes. The low income weatherization and bill assistance in APS' Energy Wise program is one of several low-income programs that APS sponsors. With the Energy Wise program, the Company's objective has been to spend $500,000 per year on low-income DSM programs. From 1999 to 2003, the Company has spent on average $427,976 per year on low income weatherization programs. This does not reflect any reluctance of the Company to spend money on low income weatherization programs, but rather implementation challenges with the various public service organizations that administer the low-income weatherization program. For example, APS fully allocates the annual funding for this program among a number of local agencies, which implement the program based on the expected level of program participants in each location. ACAA, the administrative arm of the Community Action Agencies, is responsible for reallocating funds when it becomes apparent that some agencies are not spending their allotted amount. However, sometimes the under-participation is not recognized until late in the year, when it is too late to reallocate elsewhere. Other times, the local agency is reluctant to give up funds early in the year in the hope that they can increase their program participation and use the "excess" funds to serve needs in their area. In either case, the result is that the $500,000 budget can be under-spent even though fully allocated and approved by APS. The Company is continuing to work with the ACAA and the local organizations to resolve implementation issues. Also, as discussed in the rebuttal testimony of Mr. Hines, the Company is proposing changes to the program that will address deployment issues and increased spending in the future.

D. PROPOSED EXPANDED DSM PROGRAM

Q. HAS THE COMPANY INCLUDED FUNDS FOR DSM PROGRAMS IN ITS RATE APPLICATION?

A. The Application includes the program costs of our current DSM and Energy Wise low-income weatherization programs. Total expenditures for these programs were roughly $1.1 million in the test year. These current programs are funded through the system benefits charge, which also generates approximately half of APS' EPS funding as well as funding for low income assistance.

Q. COMMISSIONER HATCH-MILLER REQUESTED THAT APS CONSIDER AN EXPANDED DSM PROGRAM AND ASSESS RECENT DSM PROGRAMS IN SEVERAL WESTERN STATES. DO YOU RECALL TO THAT REQUEST?

A. Yes. In the letter I referenced earlier in my rebuttal testimony, Commissioner Hatch-Miller asked APS to discuss the possibility of implementing a more comprehensive DSM/market transformation program and to investigate recent DSM programs recently implemented in Nevada and other states in the West.

Q. WHAT CHANGES TO THE CURRENT DSM PROGRAMS IS THE COMPANY PROPOSING ?

A. In response to Commissioner Hatch-Miller's letter and after considering the testimony of Staff, RUCO and SWEEP, APS proposes to expand its current market transformation programs. Specifically, APS sees value in expanding the current residential builder and HVAC contractor programs as well as implementing new programs targeted toward commercial customers such as new construction and schools. APS also would propose to expand current spending on low-income weatherization with some recommended changes to improve that program. I believe that these new and expanded market transformation-type DSM programs could be accomplished for roughly $3 million dollars per year, which is about three times our current level of DSM spending. The specific details of the Company's proposals for an expanded DSM effort are provided in Mr. Hines' rebuttal testimony.

Q. ARE THERE OTHER WAYS TO IMPROVE ENERGY EFFICIENCY IN ARIZONA THAT DOES NOT REQUIRE UTILITY CUSTOMER FUNDING?

A. Yes. As in other states, the Commission could explore parallel options that increase energy efficiency without requiring customer dollars to fund DSM programs trying to achieve the same results. For example, the implementation of municipal energy efficiency codes for new commercial construction could be another appropriate and cost-effective way to achieve additional benefits for commercial customers. Codes would require legislative action to implement and would need to involve the relevant commercial building and development interest groups from the start. However, the Commission along with Arizona utilities and other parties participating in the DSM Workshops should consider working with the Arizona Legislature and supporting the development of such codes.

Q. DOES THE COMPANY BELIEVE IT IS NECESSARY TO CHANGE OBJECTIVES FOR AN APS DSM PROGRAM?

A. Not in general, although I expect that the overall goals of DSM programs will be explored further in workshops that the Commission is currently sponsoring. APS believes that it is still important to focus on managing system growth, especially during peak periods which tend to be most costly from a resource procurement perspective. We also believe it is important to implement market transformation programs that concentrate on changing the practices of builders and contractors and customer behavior through education and training. These types of market transformation programs produce more lasting changes in practices and behavior than the old-style subsidized DSM programs of the past. APS recommends avoiding rebate programs, which typically are affected with high levels of freeridership—meaning the use of customer-funded rebates to subsidize equipment purchases that would have occurred even in the absence of a rebate—as well as the expensive measurement and evaluation methods of the past that simply are not cost-effective or equitable.

Q. HOW WOULD YOU COMPARE THE NEVADA POWER DSM PROGRAM AND SIMILAR PROGRAMS IN OTHER WESTERN STATES WITH APS' PROPOSAL TO EXPAND ITS DSM PROGRAM?

A. The Company routinely monitors utility DSM programs in several western states, including programs which were recently implemented in California, Nevada, Utah, and Colorado. The specifics of these programs are discussed in the rebuttal testimony of Mr. Hines. APS can certainly benefit from observing what works and what does not work before implementing similar programs in Arizona. However, almost all of these programs are relatively new, which means that their demonstrable results are somewhat unknown.

Also, while DSM programs in other states can be informative, Arizona and APS have a different climate, customer base, resource profile, and business situation compared to other utilities in the West. These differences can have important implications as to whether DSM programs and expenditure levels in other states are appropriate for APS. For example, although APS and Nevada Power are both experiencing rapid customer growth, APS has more effectively managed that growth, presently has investment grade credit ratings, and is not currently as exposed to the wholesale spot market as Nevada Power. As a result, DSM spending at the levels in Nevada will not bring the same incremental customer and utility benefits. These differences are why a reasonable proposal such as that offered by the Company or that proposed by Staff is the more prudent way of proceeding with an expanded DSM initiative in Arizona.

Q. IS THE COMPANY RECOVERING NET LOST REVENUES OR RECEIVING ANY INCENTIVE FOR IMPLEMENTING THE CURRENT DSM PROGRAMS?

A. No. Historically, the Commission and other utility regulators in the United States have coupled either a recovery mechanism for "net lost revenues"—which is essentially foregone revenue less production costs—or a financial incentive with DSM programs to eliminate the adverse financial impact to a utility that results from implementing DSM programs. APS recovered both net lost revenues and a financial incentive as part of its DSM programs from 1992 to 1999. Although today APS is not receiving any incentives or recovery of net lost revenues for its DSM programs, these become necessary considerations for any significantly increased DSM effort. A discussion of net lost revenues is provided in the rebuttal testimony of Mr. Hines.

Q. HOW WOULD APS PROPOSE RECOVERING COSTS ASSOCIATED WITH AN EXPANDED DSM PROGRAM ?

A. Any expansion of the current DSM program would require additional funding above the $1.1 million included in APS' Application to ensure that the allowed funding is consistent with the overall cost of implementing new DSM programs. If the Commission decides to increase DSM funding above the amount currently in APS' base rates, an adjustment mechanism similar to that proposed by Staff witness Barbara Keene is the most appropriate mechanism. APS had proposed, and the Commission approved, in Decision No. 66567 (Nov. 18, 2003) a System Benefits Adjustment Clause ("SBAC") shown on Schedule SBAC-1 in the Application that could be used to provide for DSM funding. APS witness David Rumolo discusses how DSM funds could be recovered through the SBAC that was approved by the Commission. As detailed in Mr. Rumolo's rebuttal testimony, APS proposes that a ceiling for DSM programs be set in Schedule SBAC-1 at a level of $10 million per year.

As I discussed earlier, the Company believes that an expanded DSM program initially funded at $3 million per year would provide reasonable additional opportunities for customer savings while assuring that programs are implemented in a cost-effective manner. However, the $3 million does not include any funding for net lost revenues, utility financial incentives, or incremental staffing costs above levels included in the Company's rate application. The $10 million ceiling would allow for any additional future funding requirements or other additional costs such as net lost revenues, as well as costs that result from recommendations from the DSM workshops or other subsequent proceedings.

V. LOW INCOME MARKETING

Q. WHAT IS THE COMPANY'S RESPONSE TO ACAA WITNESS BABIARS CONCERNING THE MARKETING OF THE LOW INCOME E-3 RATE DISCOUNT?

A. APS serves approximately 25,500 customers through the low income E-3 rate discount program, resulting in total annual discounts of over $2.9 million for year-end 2003. Under the program, eligible low income customers receive a reduction of their electricity costs ranging from 10 to 30 percent depending on their usage (the lower the usage the higher the discount). APS contracts with the Arizona Department of Economic Security Community Services Administration ("DES") to administer the E-3 program for an annual fee of $72,000 (the $56,000 annual fee referenced by Mr. Babiars was changed in July 2003). Also, APS spends additional funds on the program for applications, collateral material, billing inserts to notify customers about the program, and other administrative costs. In 2003, these additional administrative costs amounted to roughly $26,000.

APS believes that the current marketing of the program is effective. However, the Company concurs with Mr. Babiars that additional marketing of the E-3 rate discount could result in more participation among qualifying low income customers. Thus, APS proposes to provide an additional $50,000 funding per year to increase the marketing of the program and to further build awareness among low income customers. APS still believes that DES is the best channel for building program awareness because they are best suited to identify, locate, and deliver materials to potential participants. Thus, the Company would work with DES and the Community Action Programs to identify the most effective use of such increased marketing funds.

VI. COMMUNICATION PROGRAM EXPENSES

Q. WHAT DOES STAFF PROPOSE CONCERNING WHAT STAFF CHARACTERIZES AS THE COMPANY'S ADVERTISING COSTS?

A. Staff witness Dittmer proposes disallowing almost two-thirds of the Company's test-year communication program expenses because he argues that the message associated with those costs does not fit into a category that he considers acceptable.

Q. WHAT REASON DOES STAFF GIVE TO SUPPORT THIS DISALLOWANCE?

A. Mr. Dittmer asserts that what he characterizes as advertising was intended for corporate image-building and therefore is "unnecessary if APS actually provides safe and reliable service." He further states that there is "no reason" to do such "advertising" except "in a competitive open market." This analysis ignores the Company's good faith business judgment that a regulated electric utility like APS should engage in reasonable communications programs to assure the public of access to safe and reliable energy, given the recent turmoil in the energy markets and the disastrous experiences of utility customers in other jurisdictions.

Q. DO YOU DISAGREE WITH MR. DITTMER'S PROPOSED DISALLOWANCE?

A. Yes. I disagree with Mr. Dittmer's proposed disallowance because it over-simplifies the value and the purpose of this particular communications program to the customer. Management must determine what the concerns of its customers are and how the Company can best address those concerns. Advertising is one of the many avenues used by all businesses to address customer concerns and the fact that APS is a regulated utility does not make this type of advertising any less necessary or any less prudent. As the energy crisis in California over the last several years clearly showed, customers of a regulated utility can have real concerns regarding stability and reliability, just like a customer of a non-regulated entity. It is sound business practice to address customers' real concerns through communications like those Mr. Dittmer calls "image building."

Q. WHAT ARE THE CONCERNS OF CUSTOMERS OF A REGULATED ENERGY PROVIDER?

A. The chaos within the electric industry in the last few years has raised some very real and significant concerns to the consuming public. These stem from the widespread media coverage of blackouts, rolling blackouts, bankruptcies, security threats and skyrocketing rates in other states and across the country. When people see what is going on in other areas of the country, and right next door in California, they can certainly be concerned about whether it can happen in Arizona. The fact that the Commission itself changed course on electric restructuring during the test year is further evidence of the reasonableness of concerns perceived by the public regarding a reliable and stable electric supply in Arizona at this time. To ignore these concerns would be a disservice to the Company's customers, who should know that the company that provides their electric service is one that is both dependable and stable.

Q. HOW DOES THE COMPANY COMMUNICATE THIS MESSAGE TO ITS CUSTOMERS?

A. The Company uses general public resources, as well as targeted messages. The Company's activities include a wide variety of television and radio messages, collateral materials, bill inserts, sponsorships and other communication programs. These activities are generally intended to inform and educate customers concerning the Company's services, rates and tariffs, environmental and safety issues, programs and events, and other public service issues. This includes efforts to educate customers how to better use APS' services, to make it easier and more convenient to do business with the Company, to find ways for the customer to use our product more efficiently and economically, and to generally improve customer relations and satisfaction. It is also intended to address the general public's concern for reliability and stability.

Q. WHAT ABOUT THE EXPENSES THAT MR. DITTMER CLAIMS WERE PROMOTIONAL OR AIMED AT IMAGE BUILDING?

A. Mr. Dittmer refers to these actual APS costs as "objectionable" because the message is not one of six specific customer messages that he believes should be allowed. Apparently, Mr. Dittmer believes that as long as the service is regulated, that is sufficient assurance for the public, and the Company should be silent, despite APS' business judgment of its customers' concerns. Mr. Dittmer even acknowledged that these costs "are designed to promote APS as a highly reliable, affordable, customer-friendly and cost-effective company", but he fails to consider these issues and concerns as valid customer concerns in reaching his conclusion. APS, however, has to take into account the business environment in which it operates. The turmoil in the energy industry was that environment when this communications program was implemented. Reliability and affordability are genuine concerns of APS' customers, given the widespread media reporting of energy shortages, blackouts and utility bankruptcies.

Q. ARE THERE DIRECT AND TANGIBLE CUSTOMER BENEFITS THAT ARE DERIVED FROM PROGRAMS THAT COMMUNICATION INFORMATION ABOUT THEIR SERVICE TO CUSTOMERS?

A. Absolutely. Although it can be difficult to identify, track and monitor the tangible benefits of many different types and forums of customer communications, there are certainly direct benefits to the Company's customers through APS' customer outreach, and in particular its "Simple Things" campaign. The Company and ultimately customers benefit when the general public—consisting of both customers and investors—is confident that one of the largest energy providers in the Southwest is stable, "doing loads of things to make sure electricity is there when and where you need it", and is available to customers "day and night", unlike the many experiences that had been reported in the national newspapers. When a company continues to communicate to the public with such programs during a time of uncertainty and instability, the consumer is reassured that the energy so critical to their lives will be there when needed. The successful results of this effort were borne out by the extremely high and improving customer satisfaction ratings of APS during this period and by continued customer conservation efforts to help APS in assuring continued reliable service.

VII. PWEC AIR PERMITS

Q. DID STAFF WITNESS JARESS DISCUSS APS' APPLICATION FOR AIR PERMITS BY APS FOR THE PWEC WEST PHOENIX AND SAGUARO PLANTS?

A. Yes. Ms. Jaress stated in her testimony that the Financing Application raised the "concern" that PWEC received an "unfair competitive advantage" when APS applied for air permits at the West Phoenix and Saguaro sites. In her testimony, Ms. Jaress concludes that "it is doubtful that PWEC benefited significantly from this action on the part of APS" because PWEC paid APS for all costs associated with obtaining the air permits.

Q. DO YOU AGREE WITH MS. JARESS?

A. I certainly agree that PWEC did not receive an "unfair competitive advantage" because APS applied for the air permits. I was, however, disappointed that Ms. Jaress failed to mention that APS was required by federal and state law to obtain these permits on behalf of PWEC. APS explained in detail in its June 13, 2003 Report to the Arizona Corporation Commission, which is provided with Mr. Davis's rebuttal testimony, the applicable Environmental Protection Agency

("EPA") regulations and the relevant interpretive guidance. Those requirements state that because APS and PWEC are under common corporate control (they are both subsidiaries of Pinnacle West) and the power plants belong to the same category of industrial sources, they are considered one "major source" and require a single air permit. Also, APS has obtained air permits for other parties in jointly-owned plants, such as Cholla, and there has never been a suggestion that doing so was somehow inappropriate.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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Appendix A

Statement of Qualifications
Edward Z. Fox

Ed Fox is Vice President for Communications, Environment and Safety at Arizona Public Service Company (APS). In this capacity, Mr. Fox is responsible for all external and internal communications. He is also responsible for environmental, health and safety compliance and oversees the company's Technology Development group that identifies and helps bring to market emerging technologies such as solar energy and fuel cells and where he oversees the Environmental Portfolio Standard.

Mr. Fox is the former Director of the Arizona Department of Environmental Quality (ADEQ where he served the State from 1991 to 1995. Prior to coming to Arizona in 1985, he was an Assistant Attorney General in West Virginia. From 1985 to 1991, Mr. Fox was in private practice in Phoenix and Tucson, Arizona, where he represented business clients on state, federal and local environmental issues.

Mr. Fox received his J. D. from the West Virginia University. He holds a Masters in Public Administration and a B. A. from the American University in Washington, D.C.

Mr. Fox has provided leadership for numerous organizations and initiatives. For example: he is the chair of the State Trust Land Reform Committee; he recently chaired the Arizona Department of Environmental Quality's Air Quality Cap and Trade Committee, which looked to develop market mechanisms to help improve air quality in the Valley; he served as a member of the Governor's Brown Cloud Committee; and, he chaired a sub committee of the Governor's Growing Smarter committee.

Mr. Fox is also associated with the following organizations: ASU Morrison Institute, Arizona Zoological Society, United Way, Arizona Town Hall, ASU Herberger Center for Design Excellence and Valley Partnership

CURRENT EPS FUNDING REQUIREMENT FOR 2007

A. ENERGY REQUIREMENTS FOR SOLAR IN 2007

EPS goal:
1.1% of total APS annual retail energy sold in 2007[1]
1.1% X 28,550,000 MWh = 314,067MWh

1) Generation required from Solar:
60% of EPS goal in 2007 is required to be generated by solar, with 2X multiplier
314,067MWh X 60% / 2 = **94,220 MWh**

2) Solar generating sources installed in 2004:
APS central plant – 5.9MW installed, at 23% capacity factor
5.9MW X 23% X 8760 hrs/yr = **11,887 MWh**

3) Customer owned solar generation[2]
2,000 MWh (PV DG)

MWh Shortfall for EPS solar requirement in 2007 (Item 1 – (Item 2 + Item 3))
80,333 MWh in 2007

Solar Capacity needed to meet solar goal by 2007
80,333 MWh / (23% x 8760 hrs/yr) = **39.9 MW** by end of 2006

B. FUNDING SHORTFALL FOR SOLAR BY END OF 2006

1) Funding required to build solar capacity
39.9 MW x $4.5/watt x 1,000,000 watt/MW = **$179.4 million** by end of 2006

2) Funding available to meet 2007 EPS solar goal
Collections in 2005 and 2006 = $27.35 million[3]
Less: Commitments for Non-solar = $8 million[4]
Funding available: **$19.35 million**

Funding shortfall for solar in 2005 and 2006 (Item 1 – Item 2) $**160.07 million**

C. COLLECTION SCHEDULE NEEDED

2005	**$80 million**
2006	**$80 million**

D. ASSUMPTIONS AND FOOTNOTES

1. Retail energy sold increases at 3% per year.
2. Continue PV buy-down at $4/watt dc.
3. Assumes current funding program continues.
4. Non-solar ("other resources") includes PPA's for biomass, biogas and wind.

Schedule EZF-2RB

EPS FUNDING AFTER REMOVING CUSTOMER CAPS

A. 2002 USAGE BY SURCHARGE CATEGORY

Residential – 10,447,596 MWh
Small Commercial – 10,338,456 MWh
Large Commercial – 2,575,703 MWh

B. FUNDING AVAILABLE BY SURCHARGE CATEGORY

Funding surcharge = 0.000875 $/kWh

Residential
10,447,596 MWh X 1000 kWh/MWh X 0.000875 $/kWh = $9,141,646

Small Commercial
10,338,456 MWh X 1000 kWh/MWh X 0.000875 $/kWh = $9,046,149

Large Commercial
2,575,703 MWh X 1000 kWh/MWh X 0.000875 $/kWh = $2,253,740

C. TOTAL EPS FUNDING AVAILABLE IF CAPS ARE REMOVED

2002	**$20,441,535**
2003	**$21,054,478**[1]
2004	**$21,686,424**[1]
2005	**$22,337,017**[1]
2006	**$23,007,127**[1]

[1] Extrapolated based on 3% annual increase in customer usage

EPS PROGRAM GENERATION
PROJECTED AS OF DECEMBER 31, 2007

A. SOLAR REQUIREMENT AND GENERATION

1. **Solar requirement** – 60% of retail sales:
   28.55 MMWh X 1.1% X 60% = 188,440 MWh

2. **Solar available**

Customer owned (PV DG)	2000 MWh
APS owned	+11297 MWh
Total Solar	13,297 MWh X 2 multiplier = 25,162 MWh

Capacity met (Item 2 / Item 1) = **13%**

B. OTHER (NON-SOLAR RENEWABLE) REQUIREMENT AND GENERATION

1. **"Other" requirement** – 40% of retail sales:
   28.55 MMWh X 1.1% X 40% = 125,626 MWh

2. **"Other" available**

Verde wind PPA	32000 MWh
Eager Biomass PPA	21000 MWh
91st Avenue WWTP Biogas PPA	75000 MWh
Solar hot water generation	2688 MWh
Industrial solar hot water	+ 1531MWh
	132219 MWh

Capacity met (Item 2 / Item 1) = **105%**

C. TOTAL CAPACITY MET

SOLAR	**13%**
OTHER	**105%**

System Benefits and Renewables
Annual Expenditures ($) 1996 – 2003

Year	Low income Energy Wise Program* (A)	DSM-Market Transformation ("MT") (B)	Total DSM (A)+(B)	Renewables in System Benefits (C)	Total System Benefits (A)+(B)+(C)	Renewables from EPS Surcharge (D)	Total Renewables (C)+(D)
1996	41,308	7,657,883	7,699,191	3,171,274	10,870,465	Not Applicable	3,171,274
1997	215,202	5,301,565	5,516,767	2,997,624	8,514,391	Not Applicable	2,997,624
1998	232,213	2,881,245	3,113,458	3,843,274	6,956,732	Not Applicable	3,843,274
1999	434,763	1,775,108	2,209,871	3,796,324	6,006,195	Not Applicable	3,796,324
2000	462,990	409,967	872,957	5,287,961	6,160,918	Not Applicable	5,287,961
2001	399,365	4,591,978**	4,991,343	5,632,266	10,623,609	Not Applicable	5,632,266
2002	394,354	718,706	1,113,060	5,588,206	6,701,266	6,826,246	12,414,452
2003	448,407	559,828	1,008,235	6,086,290	7,094,525	9,829,543	15,915,833
Total	2,628,602	23,896,280	26,524,882	36,403,219	62,928,101	16,655,789	53,059,008

* Energy Wise Program includes weatherization and bill assistance.

**2001 DSM/MT spending includes $629,270 for MT programs and $3,912,710 for a special MT campaign to conserve energy during the summer of 2001 at the height of the regional energy crisis. This effort was part of the Arizona Governor's initiative to help manage this crisis.

APS-8R

EXHIBIT

APS-8R
admitted

REBUTTAL TESTIMONY OF

ALAN PROPPER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

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REBUTTAL TESTIMONY OF ALAN PROPPER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. INTRODUCTION

Q. WOULD YOU STATE YOUR NAME?

A. Alan Propper

Q. ARE YOU THE SAME ALAN PROPPER WHO FILED DIRECT TESTIMONY ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY ("APS") IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. The purpose of this testimony is to rebut certain cost-of-service and pricing aspects of the testimony of Arizona Corporation Commission ("Commission") Staff witnesses Lee Smith and Erinn Andreasen, Residential Utility Consumer Office ("RUCO") witnesses John Stutz and Richard Rosen, Arizona Community Action Association ("ACAA") witness Brian Babiars, and Constellation NewEnergy/Strategic Energy, L.L.C. ("Constellation") witness Mark Fulmer.

Specifically, I address matters related to Cost Allocation, Pricing Criteria, Residential Rates, Transmission Matters, and Competition Issues. I also address questions regarding the functionalization and allocation of Redhawk transmission asked by Commissioner Gleason in his letter of October 29, 2003. In addition to my rebuttal related to the ratemaking issues mentioned above, APS witness David Rumolo addresses other significant pricing-related issues concerning General Service Rates, Adjustment Clauses, and Service Schedules.

II. SUMMARY OF TESTIMONY

Q. WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. With regard to Cost Allocation, Staff and RUCO were the only parties to take issue with APS' study. For fixed generation capacity costs, Staff witness Lee Smith and RUCO witness Stutz both propose changing the cost allocation methodology from the long established coincident peak methodology ("4CP") that APS has used, and both this Commission and its federal counterpart has accepted, to methodologies that introduce energy or average demand into the allocations. Their recommended changes do not reflect cost causation and should not be further considered for a utility with load characteristics such as those of APS. Further, Dr. Stutz argues that distribution-related costs should be allocated on both a demand and energy basis. This incorrectly ignores the fact that distribution costs are designed on the basis of demand and customers, and are not related to the energy use of a particular customer or class of business.

With regard to Pricing Criteria, it appears that all intervening parties realize that there are many considerations that go into establishing relative rate levels and rate designs. However, all appear to have selected criteria and weightings in a manner that would favor their clients at the expense of overall reasonableness. This is to be expected, but does not make for the establishment of a fair and reasonable general tariff. APS has used the Bonbright principles, in conjunction with current and historical APS and industry practices, in developing its proposed rates.

With regard to Residential Rates, some parties took issue with various aspects of APS' proposed rate levels and designs. APS' proposed rate designs, however, are sound and follow well-established and widely-recognized standard principles. Where possible, I have accepted the recommendations of Staff and intervenors on certain residential rate design issues, though generally with necessary clarifications. However, APS does not agree to Staff's recommendation for different (and split) on-peak and off-peak hours for winter and summer for the ET-1 and ECT-1R rates. In addition to causing customer confusion, such a recommendation is not technically practical due to metering and billing limitations. APS also cannot agree with Staff's and RUCO's recommendations on residential rate design that would cause even further divergence from cost.

With regard to Transmisson Matters, I strongly disagree with RUCO witness Rosen's argument that federal jurisdiction over transmission can simply be ignored by the Commission. I also do not believe his recommendation to oppose the formation of a Regional Transmission Organization is appropriate in this rate case.

I also disagree with some of the retail Competition Issues articulated by Constellation witness Fulmer, including those relating to Revenue Cycle Services and transmission pricing. In addition, I have responded to Commissioner Gleason's questions on Redhawk transmission.

III. COST ALLOCATION

Q. WOULD YOU DISCUSS WHERE YOU TAKE EXCEPTION TO THE COST ALLOCATION-RELATED TESTIMONIES OF THE STAFF AND INTERVENOR WITNESSES?

A. Yes, but I would first note that only Staff and RUCO have taken any exception to the cost allocation study APS has presented in this proceeding, and those exceptions relate to the important but relatively straightforward issue of the methodology used in the classification and allocation of costs. Staff witness Lee Smith and RUCO witness Stutz have chosen to use cost allocation methodologies that incorporate energy into the allocation factors used to allocate generation capacity costs. Ms. Smith has used a method commonly referred to as the

"Average & Peak" method, while Dr. Stutz has chosen to use the average of APS' demand and energy allocators. Using methodologies that incorporate a combination of energy and demand into the allocation of generation capacity costs inappropriately lessens the cost responsibility of retail customers as well as the lower load factor classes that partly comprise the Commission's jurisdiction when compared to the demand allocation methodology that APS has consistently used for many years. Moreover, neither the Staff nor RUCO methodologies are appropriate for APS' system. APS has long used the demand-related "Coincident Peak", and specifically the "4CP" methodology, which allocates generation and transmission capacity related costs based on contributions to the average of the coincident peak demands during the months of June, July, August, and September. This is true whether APS' cost allocation studies have been performed for Commission proceedings, Federal Energy Regulatory Commission ("FERC") proceedings, or for the internal use of APS.

Though various methodologies have been considered both now and in the past for the allocation of generation facilities, there are several reasons for continuing to use a Coincident Peak methodology as opposed to the methodologies proposed by Staff and RUCO:

1. The 4CP methodology best reflects generation capacity cost responsibility for a consistently strong summer peaking utility such as APS.

2. The Coincident Peak methodology uses a true demand (kW) allocation for what is a fixed cost, namely generation capacity, as opposed to an energy (kWh) allocation which is suitable for use with a variable cost such as fuel expense.

3. APS has consistently used the Coincident Peak methodology for many years as the basis for cost allocation for filings with both the Commission and FERC, as well as for internal studies, and there has

been no occurrence that leads me to believe that a methodology change is warranted or desirable.

4. The Commission has consistently accepted the 4CP methodology in APS proceedings.

5. FERC consistently uses the Coincident Peak methodology for performing embedded cost allocation studies when dealing with APS and other utilities under its jurisdiction. In fact, the transmission rate component inherent in APS' proposed rates is based on a 4CP methodology as required by FERC.

6. The consistent use of the 4CP methodology by APS and the Commission over so many years has allowed trends to be recognized, and suitable relative rates of return to be established for the various classes of service.

7. Most utilities around the country use Coincident Peak for cost allocation purposes. APS has no reason to believe it should be an exception.

8. The methodology is consistent with the procedures discussed and outlined in the NARUC _Electric Utility Cost Allocation Manual._

Q. IN ADDITION TO THE RATIONALES FOR USING A COINCIDENT PEAK METHODOLOGY LISTED ABOVE, ARE THERE SPECIFIC REASONS THAT YOU DO NOT ACCEPT THE AVERAGE & PEAK OR OTHER ENERGY RELATED METHODOLOGIES AS A LEGITIMATE ALTERNATIVE FOR ALLOCATING GENERATION CAPACITY COSTS?

A. Yes. An energy-related methodology is not conducive to ratemaking purposes at APS for several reasons. First, the indices of return (the relative rates of return of the various classes when compared to the overall rate of return of the jurisdiction) have been determined for historical test years and established for proposed rate levels on the basis of the 4CP methodology for many years. A sudden and arbitrary change in cost allocation methodology that is unsupported by an actual change in cost causation makes it virtually impossible to observe the historical relationships and trends needed by the rate designer when establishing revenue requirements for classes of business and individual rates. This, in turn, increases the potential for rate shock or, in the alternative, will cause further deviation from the cost-of-service when designing rates. In any case, because our proposed absolute and relative class rates of return are based on the 4CP methodology, a change to another methodology would necessitate consideration of possible compensating changes to what have been proposed by APS as suitable class returns.

Second, if carried to an extreme, the introduction of energy or average demand, which is a highly variable classification of cost, into the allocation of a fixed cost such as generation capacity could lead to an inappropriate rate design that attempts to recover a major fixed cost through a charge based on variable energy usage. Such a rate design would produce highly volatile, non-cost based and erratic revenues not suited for effective cost recovery.

Third, a cost allocation study should be "pure" and truly reflect, on a consistent basis, the cost of providing electric service to jurisdictions, classes of business, rate schedules, and to the degree possible, individual customers. Picking a methodology that will arrive at a desired end result for a particular rate level or rate design is not appropriate. The practicalities and politics of ratemaking should be reflected by the rate designer through considerations that warrant deviating from a true cost allocation study. These other considerations have been referenced by Dr. Stutz as Professor Bonbright's criteria for ratemaking. Though I have significant disagreement with many of Dr. Stutz's concepts on ratemaking, I am in general agreement with his acceptance of Bonbright's criteria as expressed in the treatise _Principles of Public Utility Rates_.

Fourth, if one were to adopt an allocation methodology in which energy were to be used to allocate a portion of the fixed cost of capacity, then perhaps a significant and possibly offsetting portion of the variable cost of fuel should be allocated as demand-related. To me, this is both unreasonable and unworkable. A variable expense, such as fuel, should be allocated on a variable factor such as energy. A fixed cost, such as power plant capacity, which APS will incur regardless of level of use, should be allocated on a basically fixed item such as demand. The benefits of our system being fully integrated and having a mix of power plants and resources and a mix of customers with differing load factors and characteristics should flow through to all of our customers. Allocating power plant capacity based on demand and power plant variable expense based on energy does just that.

Q. WHAT EFFECT DOES THE AVERAGE & PEAK COST ALLOCATION METHODOLOGY PROPOSED BY MS. SMITH HAVE ON APS' ABILITY TO RECOVER THE TOTAL COMPANY REVENUE REQUIREMENT?

A. The Average & Peak cost allocation methodology is inconsistent with the 4CP methodology accepted and required by FERC for use in APS' FERC rate proceedings. Average & Peak shifts approximately $5.1 million in annual costs or revenue requirement away from APS' Commission jurisdictional customers and inappropriately places it on the non-jurisdictional FERC customers. Since FERC does not accept the Average & Peak methodology, APS would not be able to recover this $5.1 million in cost from either jurisdiction, effectively "stranding" dollars between state and federal regulation.

Q. IF THE COMMISSION APPROVES MS. SMITH'S PROPOSED AVERAGE & PEAK COST ALLOCATION METHODOLOGY, SHOULD IT BE UTILIZED TO ALLOCATE GENERATION RELATED CAPACITY COSTS BETWEEN APS' COMMISSION JURISDICTIONAL AND FERC JURISDICTIONAL CUSTOMERS?

A. No. At a minimum, the 4CP methodology should still be used to allocate generation related capacity costs between the Commission and FERC jurisdictions. If the Commission elects to utilize the Average & Peak methodology, it should only be applied to generation-related capacity costs to be allocated among the Commission jurisdictional classes of business. In addition, these costs should continue to be considered as demand-related in the design of rates, as is implicitly expressed in the Average & Peak cost allocation methodology.

Q. ARE THERE ANY OTHER RECOMMENDATIONS BY STAFF OR INTERVENORS CONCERNING COST ALLOCATION THAT YOU WISH TO REBUT?

A. Yes. Dr. Stutz argues on behalf of RUCO that distribution costs should be classified and allocated as both demand and energy related. This is a significant and unwarranted change, since without notable exception, such costs have always been considered demand and customer related.

Specifically, distribution costs are simply not related to energy use. Utilities design their distribution systems to meet customers' non-coincident peak demands. A utility's investment in distribution plant is thus a function of demand, and not a function of the amount of energy that customers use over some period of time. If a customer were to take little or no energy during a specific time period, it would not change what distribution facilities the utility must install in order to provide safe and reliable service to this customer. Designing rates in which the distribution component is based in part on energy causes erratic cost recovery and simply does not allow cost recovery to be related to cost causation. As I can attest, with regard to APS' proposed rates this hampers the unbundling of rates and competition for Revenue Cycle Services ("RCS") such as billing, metering, and meter reading.

There are general and specific practices and procedures that those responsible for determining costs and designing rates need to follow to produce a tariff that is reasonable and in accordance with precedents established in our industry. These practices and procedures for performing reasonable and acceptable cost allocation studies are expressed in NARUC's *Electric Utility Cost Allocation Manual*. Though a rate expert performing a cost allocation study is certainly free to deviate from established precedents if there is a basis for doing so, a recommendation such as the one put forth by Dr. Stutz is an unfounded attempt to direct costs away from his client's responsibility.

Q. HAVE YOU PERFORMED ANY ADDITIONAL COST ALLOCATIONS IN CONJUNCTION WITH THE REBUTTAL TESTIMONIES SUBMITTED BY APS?

A. Yes. I performed jurisdictional allocations on the additional proforma adjustments shown in APS witness Donald Robinson's rebuttal testimony. The same methodology used in the allocation of the originally filed proforma adjustments, and discussed in my direct and rebuttal testimonies, was used to perform the allocations on the additional adjustments.

IV. PRICING CRITERIA

Q. WAS COST ALLOCATION AND THE RESULTING JURISDICTIONAL AND CLASS COST-OF-SERVICE STUDY THE ONLY BASIS FOR APS DEVELOPING THE RATES PROPOSED IN THIS PROCEEDING?

A. No. It was only a starting point. The cost allocation study allowed me to see what rate levels and rate designs would be if cost causation was the only criterion for ratemaking. Bonbright's non-cost-of-service criteria then came into consideration. It is a simple truth that these other criteria are basically qualitative and therefore subjective in nature and cannot be quantified except through an analysis of how much the revenue produced by a specific rate deviates from a purely cost-based rate. As is typical in a major rate case, intervenors in this case have proposed alternative revenue levels that would reduce the revenue requirements to be contributed by each of the intervenor's constituents.

Q. OTHER THAN COST-OF-SERVICE, WHAT ADDITIONAL CRITERIA WERE CONSIDERED WHEN DEVELOPING THE PROPOSED RATES?

A. The most obvious criterion that I felt had to be taken into consideration was straight from Bonbright—"Effectiveness in yielding total revenue requirements under the fair-return standard." In other words, we are dealing with a "zero-sum" situation. The rate designer must deal with a total revenue target and cannot reduce the revenue responsibility of one group of customers without identifying another group to make up the difference.

Next came "Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers." It was this criterion that primarily caused the proposed rates, both as to level and design, to not strictly follow costs. Though changes to the current rate designs were deemed necessary to keep rates from continuing to stray further and further from the actual cost to serve, such changes were limited to avoid as many customer billing dislocations as possible while still proposing fair and reasonable rates. This is in line with Bonbright's criterion—"Avoidance of undue discrimination in rate relationships."

Another criterion that was considered was "Revenue (and income) stability from year to year." A conscious effort was made to relate incremental costs and incremental revenues.

Also, consistent with Bonbright, "The practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application" were all considered. The issue of simplicity becomes somewhat more complex due to the need to unbundle the retail rate schedules in accordance with the Commission's Retail Electric Competition Rules ("Competition Rules").

Finally, other Bonbright criteria, as well as additional principles, were taken into account but, in general, did not explicitly affect the establishment of the proposed rates.

Q. IN GENERAL TERMS, WOULD YOU SUMMARIZE THE CRITERIA USED IN DEVELOPING THE RATES AS PROPOSED BY APS IN THIS PROCEEDING?

A. The two most significant criteria were cost to serve and stability of the rate design. The cost allocation study provided absolute and relative rates of return at current rate levels for the jurisdiction, classes of business, selected sub-classes, and individual residential rate schedules. It also provided unitized demand, energy, and customer costs. This enabled APS rate designers to impute hypothetical rates that would be based strictly on the cost to serve. The current rates were then carefully examined and considered so that relative rate levels and designs could be preserved to the extent possible. In effect, these two criteria were merged and balanced to develop a new set of proposed rates. In addition, modifications were made where necessary to account for additional Bonbright and other principles as discussed above.

V. RESIDENTIAL RATES

Q. WOULD YOU DISCUSS YOUR DISAGREEMENTS WITH THE TESTIMONY OF COMMISSION STAFF WITNESS ANDREASEN CONCERNING RESIDENTIAL RATES?

A. Ms. Andreasen's rate-related testimony is difficult to address or rebut because it is based on a Staff recommended rate decrease of 8.0% as opposed to the 9.8% increase requested by APS that was used to develop proposed rates. In addition, she has not produced a specific set of Staff proposed rates, but only some general parameters or guidelines under which such rates would be developed. If a rate decrease is ordered by the Commission, the rates proposed by APS would have to be completely revised. Even if a significantly lower increase than that proposed by APS were ordered by the Commission, the recommendations of both Staff and APS would have to be revisited. In other words, APS could not just proportionately scale back the rates as APS had proposed them or simply adhere to Staff guidelines to produce new rates. Rather, the entire tariff would have to be redesigned for compliance, taking into account the final Commission order and how it addresses the recommendations of APS, Staff, and intervenors, as well as the Competition Rules. This, of course, also holds true for the general service rates that APS witness David Rumolo discusses.

Q. ARE THERE ANY AREAS OF MS. ANDREASON'S TESTIMONY CONCERNING SPECIFIC RESIDENTIAL RATES THAT YOU WISH TO COMMENT ON?

A. Yes. Ms. Andreason agrees with APS that residential rates E-10 and EC-1 should be eliminated. However, Staff recommends that customers on rate EC-1 should have a one-year phase out period, as APS has recommended for customers on rate E-10. In addition, Staff recommends that written notice be given to customers on these rates of APS' intent to cancel them and that a customer education plan be instituted to inform customers of alternative rate options. APS has no objection to these recommendations, although the additional cost of such a plan should be included in APS' revenue requirements. My only addition would be to include an interim rate, which would reflect the same percentage change as the residential class, for rate EC-1 during the phase out period. This procedure would be similar to that which APS has recommended for rate E-10.

Staff also agrees with APS that there should be alternative experimental time periods for time-of-use residential rates ET-1 and ECT-1R. Staff recommends that APS file a report after three years that evaluates the outcomes of adopting the optional time periods. APS has no objection to this recommendation. However, should the experimental time periods prove to be beneficial to APS and its customers or be in need of some modification in actual practice, APS may ask the Commission to adjust or expand the experiment prior to the end of the three-year evaluation period. In addition, if this experiment becomes a part of the regular tariff provisions, it may be necessary to alter the prices charged for the different options to more accurately track cost differentials as well as meet revenue requirements.

Staff does not agree with APS that the on-peak periods during the winter be eliminated for residential rates ET-1 and ECT-1R. In addition, Staff apparently is recommending that the winter on-peak period be changed from the current 9am – 9pm to some sort of split period that goes from 7am – 9am and 7pm – 10pm. APS does not believe that having an on-peak and off-peak rate differential in the winter is cost justified. Staff has not demonstrated that the proposed winter rate time periods provide any benefit to a summer-peaking utility. Nor has Staff proposed how these split time periods would be coordinated with the proposed experimental alternative time-of-use periods.

In response to the Staff's position, APS would have no objection if the energy charges in rates ET-1 and ECT-1R were non-time differentiated in the winter, but that the demand charges in rate ECT-1R remain time differentiated in both seasons to recognize the positive load management aspects of rate ECT-1R. However, APS does object to having different on-peak hours during the summer and winter and, in particular, split hours for the winter. Such a design would cause significant customer confusion, violate several of the criteria for good ratemaking and, in addition, require the reprogramming or replacement of some 347,000 meters and extensive modification and additional expense for accounting, billing, and customer information systems. Because meters cannot be reprogrammed in the field, a significant increase in meter inventory would be required to accomplish

Staff's proposal. It is estimated that the cost of just the meter changes alone would be over $25 million.

Q. MS. ANDREASEN STATES THAT SHE DOES NOT HAVE ANY CONCERNS REGARDING THE APPROACH APS HAS TAKEN TO UNBUNDLING ITS RATES AT THIS TIME, BUT MAY IF THE REVENUE REQUIREMENTS WERE TO CHANGE SIGNIFICANTLY. DO YOU WISH TO COMMENT ON THIS?

A. Yes. Let me reiterate and state my agreement with what Ms. Andreasen said in her direct testimony:

> Deviating from cost-based unbundled rate elements creates price signals that can lead to uneconomic distortions in the competitive market. If the ACC wishes to facilitate retail competition, an effort should be made to base unbundled rates on cost to the extent possible. However, this can be difficult because the bundled rate from which the unbundled rates are derived may not reflect the full cost due to rate design considerations.

I agree with this statement, and believe it holds true for all rates, both residential and non-residential. However, Staff's actual recommendations as to rate design contradict this statement, and go far beyond consideration of the non-cost-related Bonbright principles discussed above.

Q. WOULD YOU DISCUSS MS. ANDREASEN'S RECOMMENDATIONS REGARDING RESIDENTIAL BASIC SERVICE CHARGES ("BSC")?

A. Ms. Andreasen's recommendations regarding BSC are somewhat dependent on the amount and direction of the rate change ordered by the Commission. The change to a daily charge to ease billing problems and eliminate some controversy does not seem to be contested. However, contrary to their statements, Staff ignores both absolute and relative costs associated with providing customers with this customer-related service that is unrelated to either energy or demand. The BSC relates to providing the customer with the ability to physically receive electricity. The cost of this service varies for the different residential rate schedules, with differences in the cost of meters being the most obvious. Staff has not offered any valid reason that the costs inherent in BSC should not be borne by the customer taking the service.

In addition, maintaining current BSC rate levels is inconsistent with the cost-based rate unbundling that is necessary to facilitate Direct Access service in APS' service territory, as well as to comply with the Competition Rules. This is particularly troublesome since these costs are associated with RCS which could be provided by an Electric Service Provider ("ESP") and not APS. Current BSC rate levels are generally less than the sum of the cost-based unbundled components of the proposed rates. Therefore, Staff's BSC recommendation would have APS offer BSC services for metering, meter reading, billing, and other customer-related services at below cost. This, in turn, would mean that other ESPs would not likely be able to competitively provide these services even if their cost structure was otherwise competitive with APS.

Q. WOULD YOU DISCUSS YOUR DISAGREEMENTS WITH THE TESTIMONY OF RUCO WITNESS STUTZ CONCERNING RESIDENTIAL RATES?

A. Dr. Stutz' primary recommendations appear to be that: (1) residential rates should be lower than APS has proposed, (2) there should be uniform increases to all charges, and (3) currently frozen rates E-10 and EC-1 should not be eliminated. These recommendations are inappropriate and would shift costs incurred by the residential class to other customers. Also, it was determined at the time they were frozen that rates E-10 and EC-1 should be phased out as non-compensatory, as well as being superfluous and repetitive to the residential tariff. I find it difficult to propose rates that do not recognize cost causation and that would, in effect, be asking your neighbors to continue to pay a significant part of your electric bill or, from another perspective, would be asking you to continue to pay a major portion of theirs.

Dr. Stutz states that the price signals sent by APS' proposed residential rates may adversely affect customer investment in conservation or load management. While APS believes that time-of-use rates can be an important tool to stimulate customers to shift usage to off-peak periods and thereby save money for both the customer and APS, I also believe that those price signals should be appropriately based on relevant supply costs for the seasonal on-peak and off-peak periods. The truth of the matter is that it is incorrect and inappropriate price signals that may lead to inappropriate customer investment in conservation or load management. Thus, it is Dr. Stutz's rate proposals, not those of APS, that would lead to bad customer choices.

Q. ACAA WITNESS BABIARS RECOMMENDS THAT THE RATE E-3 DISCOUNT AVAILABLE TO LOW-INCOME ARIZONANS BE INCREASED TO OFFSET ANY RATE INCREASE THAT APS MAY BE AWARDED, AND THAT APS INCREASE ITS MARKETING OF THE E-3 RATE. WHAT IS APS' POSITION ON THIS?

A. APS has no objection to this proposal so long as any additional costs created by the increase to the discount and the increase to the marketing of rate E-3 are incorporated into the final rate levels and designs ordered in this proceeding. APS witness Edward Fox will address the rate E-3 program in greater detail.

Q. SINCE THE PROPOSED RATES ARE UNBUNDLED AS DEFINED IN THE COMPETITION RULES, WILL APS' CURRENT BILL FORMAT BE MODIFIED?

A. Yes. Because customer bills for the proposed unbundled rates will identify the competitive and non-competitive billing elements, the current "page 2" of the bill will be eliminated. This is the case for both residential and non-residential bills.

VI. TRANSMISSION MATTERS

Q. RUCO WITNESS ROSEN SEEMS TO BELIEVE THAT IT IS IN THE BEST INTERESTS OF APS' RESIDENTIAL CUSTOMERS TO ATTEMPT TO SUPPLANT FERC'S PRESENT ROLE OF REGULATING APS' TRANSMISSION SERVICE. DO YOU AGREE?

A. No. However, before I answer further I want to make it clear that I believe the jurisdictional issues raised by Dr. Rosen are essentially legal in nature and should not be dealt with in this rate case, but instead perhaps in the courts, the legislature, in rulemakings, or in some other appropriate proceeding or venue.

In any event, as a longtime practitioner of ratemaking and regulatory matters, I believe that FERC's regulatory authority is here to stay, and that an attempt by the Commission to circumvent clear jurisdictional boundaries will not only be thwarted by the federal government, but will intensify and expand the inroads FERC has already made in regulating the nation's transmission systems. If FERC determines that electric utilities are required to join some form of RTO, Arizona may not be allowed to ignore their directives. An attempt by Arizona to isolate itself from the process of RTO formation will potentially limit its input as to what structure and authorization these organizations will ultimately have should their existence become a mandatory federal policy.

Isolation is not always or automatically the best policy. What Dr. Rosen may view as the Commission giving up in its autonomy may be more than offset by the Commission's new influence or even a degree of control in regional and national transmission matters.

Q. DR. ROSEN STATES THAT "IF THE COMMISSION RETAINS JURISDICTION OVER THE BUNDLED RETAIL COMPONENT OF TRANSMISSION SERVICE IN ARIZONA, THUS HELPING TO AVOID RTO MEMBERSHIP FOR ARIZONA'S ELECTRIC UTILITIES, THIS WILL ALSO PREVENT THE ADOPTION BY FERC OF THE ADDITIONAL RETURNS ON EQUITY FOR THESE TRANSMISSION ASSETS THAT FERC HAS PROPOSED ALLOWING FOR UTILITIES THAT DO JOIN RTOS." DO YOU AGREE?

A. No. Any attempt by APS to avoid joining an RTO, even at the direction of the Commission, will likely be futile if such organizations are lawfully mandated by the federal government. The possible savings that Dr. Rosen thinks would materialize by possibly avoiding a higher return on equity for certain transmission assets could certainly be more than offset by losing the benefits that the higher return and RTO formation are intended to bring to the customers in the form of reliability and bottom-line prices, as well as the possible costs of punitive actions by FERC on Arizona utilities such as APS if we were to attempt to ignore FERC's national policy on transmission.

Q. HAS DR. ROSEN ADDRESSED APS' PROPOSAL TO INCLUDE A TRANSMISSION COST ADJUSTMENT CLAUSE ("TCA") IN ITS TARIFF?

A. Yes, and I would like to note that only RUCO has taken exception to the inclusion of a TCA in APS' tariff. Staff witness Lee Smith recommends only some relatively minor modifications to the APS proposal. Dr. Rosen's objection to its inclusion appears to be based on the fact that transmission costs are currently relatively stable. That may be true today, but volatility in either direction is a strong possibility that needs to be considered and dealt with prior to its occurrence to protect both APS and our customers.

APS is already purchasing transmission and ancillary services under its FERC accepted Open Access Transmission Tariff ("OATT") in the same manner as any other retail electric supplier. There are several elements in the OATT that involve generation-related ancillary services, some of which are subject to cost volatility. For example, energy imbalance charges are based on system incremental cost that can be far from stable. Energy imbalance, in and of itself, can be costly and volatile if a Scheduling Coordinator for retail loads significantly misschedules its loads and must rely on energy imbalance service.

In addition, once an RTO or its equivalent is operating, APS' Scheduling Coordinator will become a purchaser of transmission service from the RTO. At that point, APS will no longer control these transmission and ancillary services costs. The volatility of these costs, which could be up or down in both the short and long runs, is not known at this time and will not be fully known until an RTO is operational.

Furthermore, volatility is not the only standard that should be used to judge the worth of the TCA. In an environment of retail choice it is important that the transmission costs charged to APS' Standard Offer customers be closely matched to what these customers would pay for transmission if they were receiving Direct Access service. This comparability would allow customers to compare Direct Access and Standard Offer services without a distortion due to differences in transmission costs. The TCA would help ensure that the Standard Offer transmission charge would closely track the transmission charges that an ESP would pass on to its customers.

APS witness Rumolo discusses the APS proposed TCA in detail in his rebuttal testimony.

VII. COMPETITION ISSUES

Q. CONSTELLATION WITNESS FULMER MAKES THE STATEMENT THAT "IN GENERAL, UNBUNDLED RATES FACILITATE RETAIL CHOICE BY PROVIDING CLEAR PRICE SIGNALS TO CONSUMERS AS TO WHICH COSTS AND SERVICES, MUST OUT OF NECESSITY, BE PROVIDED BY THE INCUMBENT UTILITY AND WHICH CAN BE PROCURED THROUGH COMPETITIVE RETAILERS. THEY ALSO HELP PREVENT THE COMMINGLING OF COSTS AMONG RATE CATEGORIES. NONETHELESS, CARE MUST BE TAKEN IN ASSESSING WHICH COSTS ARE ALLOCATED TO WHICH RATE CATEGORY, AS THE SHIFTING OF COSTS FROM COMPETITIVE COMPONENTS SUCH AS GENERATION TO NON-COMPETITIVE COMPONENTS SUCH AS DISTRIBUTION WOULD SEND WARPED PRICE SIGNALS TO CUSTOMERS." DO YOU AGREE?

A. Generally, yes. My only caveat is that ratemaking is not always purely cost based. Other considerations must be taken into account that very often lead one away from the strict design criteria that Mr. Fulmer seems to believe is ideal.

Q. WHAT SPECIFIC PROBLEMS DOES MR. FULMER HAVE WITH APS' PROPOSED TARIFF PROVISIONS FOR PROVIDING RCS?

A. Mr. Fulmer's concerns involve the fact that Direct Access customers acquiring generation from a supplier other than APS must also acquire RCS from a competitive third party supplier to be in compliance with the Competition Rules. Should such services not be available from a supplier other than APS, APS would provide RCS, as has already been approved by the Commission in APS' current Schedule 10 *Terms and Conditions for Direct Access*. Under such circumstances, APS would provide selected RCS and charge the customer at an appropriate rate that would be applied to the Direct Access customer's bill. To reflect that assumption, APS has indicated in its proposed tariff that, in the absence of other RCS suppliers, competitive services such as metering and meter reading could be provided by APS. This provision would prevent the lack of competition in the metering business from being a barrier to competition for generation or other competitive services.

As to the vagueness of the term "appropriate charge", it was necessary to state the pricing in this manner as it is not known whether the Standard Offer rates for these unbundled services will include the appropriate costs for providing RCS to a Direct Access customer. APS does not want to provide potential Direct Access customers with the "warped price signals" over which witness Fulmer expressed concern and which could cause inappropriate economic decisions by customers.

Q. WHAT COMPETITION RELATED CONCERNS DOES MR. FULMER HAVE WITH TRANSMISSION PRICING?

A. They appear to be one of terminology and one related to the role of the Arizona Independent Scheduling Administrator ("AISA"). Apparently, Mr. Fulmer does not like to refer to transmission service as being "competitive". I am not sure of the significance of this, however, and the fact is that transmission service is specifically considered to be a competitive service in Rule R14-2-1606(C)(2) of the Competition Rules. Mr. Fulmer correctly states that providing transmission service is the responsibility of the Direct Access customer's Scheduling Coordinator which obtains this service from APS and, in turn, is billed by APS for these services under the OATT.

As to his statement "that this tariff should continue to be administered and interpreted by the AISA", there presently does not seem to be a clear statement or even indication as to the current or future responsibilities of the AISA. Whatever the AISA's responsibilities turn out to be, there is no reason to believe that APS would ignore any authorized directives.

VIII. COMMISSIONER GLEASON'S QUESTIONS REGARDING REDHAWK

Q. COMMISSIONER GLEASON, IN HIS LETTER OF OCTOBER 29, 2003, ASKED SEVERAL QUESTIONS RELATED TO REDHAWK'S TRANSMISSION FACILITIES. WOULD YOU PLEASE RESPOND TO THEM?

A. Certainly.

Q. MANY OF THE CALCULATIONS IN THE FILED WORKPAPERS INCLUDE REDHAWK TRANSMISSION. WOULD YOU PLEASE PROVIDE A GENERAL PHYSICAL AND ELECTRICAL DESCRIPTION ALONG WITH ITS GENERAL LOCATION?

A. The Redhawk transmission system includes a switchyard at the Redhawk plant, step-up transformers, two 500 kV lines that run from the plant's switchyard to the Hassayampa Switchyard, and an interconnection bay within the Hassayampa

Switchyard. The Hassayampa Switchyard is a jointly-owned facility operated by Salt River Project, and is connected to the Palo Verde Switchyard by means of a common bus. The Hassayampa Switchyard is part of APS' integrated network transmission system.

Q. DOES APS INTEND TO INCLUDE REDHAWK TRANSMISSION IN RATE BASE? IF SO, WOULD YOU EXPLAIN WHY THIS IS APPROPRIATE?

A. In order to interconnect a large generating facility to APS' transmission system, whether it by owned by APS, an APS affiliate, or a third party entity, three types of facilities are needed:

1. Customer Interconnection Facilities – generally step-up transformers and related equipment,
2. Transmission Provider Interconnection Facilities – the wires needed to interconnect the generating plant to APS' integrated transmission system, and
3. Network Upgrade – upgrades to the integrated transmission system needed to accommodate the interconnection of the large generating facility to the integrated transmission system.

Under FERC's Uniform System of Accounts, all facilities in items 1, 2 and 3 above are functionalized as transmission-related. However, for ratemaking purposes, FERC's policy is to functionalize items 1 and 2 as generation, inasmuch as they are not part of the integrated transmission system. Because item 3 is part of the integrated transmission system, investment in these facilities is functionalized as transmission.

If ownership of Redhawk were to be transferred to APS, any investment in the switchyard at the Redhawk plant, the step-up transformers, and the two 500 kV lines that run from the plant's switchyard to the Hassayampa Switchyard (items 1 and 2) would be functionalized as generation, and therefore included in rate base in this proceeding. Investment in facilities related to interconnection bay within the Hassayampa Switchyard (item 3) would be functionalized as transmission and not included in rate base in this proceeding since transmission-related costs are considered FERC jurisdictional.

Q. EXPLAIN ITS [REDHAWK TRANSMISSION] SPECIFIC PURPOSE AND BENEFIT IN THE PROVISION OF UTILITY SERVICE. WOULD YOU INCLUDE IN YOUR ANSWER ITS RELATIONSHIP TO APS' SPECIFIC GENERATION ASSETS AND NON-APS GENERATION ASSETS?

A. The interconnection transmission assets are needed to interconnect Redhawk to the integrated transmission system. The Hassayampa facilities are upgrades to the integrated transmission system and were required because the existing transmission system did not have adequate capacity to handle the output of the Redhawk plant. These facilities are distinct from and unrelated to APS' generation assets.

Q. WOULD YOU EXPLAIN WHY IT [REDHAWK TRANSMISSION] IS INCLUDED IN MR. DONALD ROBINSON'S WORKPAPERS AMONG PWEC GENERATION ASSETS SUCH AS IN DGR-WP1 2/12 AND OTHER CALCULATIONS?

A. The DGR_WP1 workpapers show the inclusion of all the PWEC assets in rate base, and includes 100% of the Redhawk transmission costs. As previously explained, the Redhawk transmission assets are comprised of two different types of transmission facilities, interconnection facilities which are functionalized as generation-related, and PWEC's share of the Hassayampa Switchyard costs which are functionalized as transmission facilities and were removed from rate base as part of the APS transmission pro forma adjustment. Treating functionalized transmission rate base and expenses associated with all pro forma adjustments in this manner allows the effects of each pro forma adjustment to be viewed on a stand-alone basis.

Q. WOULD YOU IDENTIFY, BY SOURCE, THE REDHAWK TRANSMISSION REVENUE INCLUDED IN THE FILING AND EXPLAIN HOW THIS REVENUE, BY SOURCE, IS PROJECTED TO CHANGE IN THE FIVE YEARS SUBSEQUENT TO THE TEST YEAR?

A. APS assumes that the "Redhawk transmission revenue" refers to transmission wheeling charges. APS receives no transmission revenue directly attributable to the Redhawk plant because the Redhawk plant is directly interconnected to the Palo Verde/Hassayampa common bus. As a result of PWEC's investment in facilities related to items 1, 2 and 3 above, power from the Redhawk plant is delivered directly to the Hassayampa/Palo Verde Switchyards over PWEC-owned facilities. Because entities purchasing the power from Redhawk would take delivery at Hassayampa/Palo Verde, there would be no transmission wheeling charges for transmission from Redhawk.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes it does.

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REBUTTAL TESTIMONY OF

DAVID J. RUMOLO

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

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REBUTTAL TESTIMONY OF DAVID RUMOLO
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME.

A. David Rumolo

Q. ARE YOU THE SAME DAVID RUMOLO WHO PROVIDED DIRECT TESTIMONY IN THIS DOCKET?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. This testimony provides rebuttal to direct testimony filed by Arizona Corporation Commission ("Commission") Staff and Intervenors. Specifically, I address the general service rate design testimony of Staff witness Erinn Andreasen; Arizonan's for Electric Choice and Competition ("AECC") witness Kevin Higgins; Kroger witness Stephen Baron; Constellation NewEnergy/Strategic Energy ("Constellation") witness Mark Fulmer; Arizona CoGen witness William Murphy; and Federal Executive Agencies ("FEA") witness Dr. Dennis Goins. I also respond to the testimony of Staff witness Barbara Keene and Residential Utility Consumers Office ("RUCO") witness Dr. John Stutz that pertains to the proposed Service Schedule changes filed in this docket. Finally, I respond to the testimony of Staff witnesses Doug Smith, Barbara Keene, and Lee Smith addressing the various adjustment mechanisms in the Company's application.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My rebuttal testimony addresses the proposed revisions of Staff and intervenors to the Company's proposed General Service rate schedules. More specifically, I provide clarification on language that was contained in these rate schedules regarding responsibility for "distribution" charges. Also, APS does not disagree with the testimony of Mr. Higgins and Mr. Baron regarding refinements to the design of Schedule E-32 as they pertain to rate blocks and charges for customers who receive service at secondary voltage. I also indicate that APS would not object to leaving the current on-peak time periods in place for customers who are served under general service time-of-use rates if the Commission agrees with Mr. Higgins that the change in on-peak times would present an undue burden on customers. However, APS does not agree with Staff's proposal to leave basic service charges at current levels because that would fail to recognize cost differences among different types of customers. I also disagree with Mr. Murphy's rate design proposal to abandon demand charges in our retail rates and with Dr. Goins' specific recommendations for voltage discounts and time-of-use price differentials.

My Rebuttal Testimony also discusses the proposed revisions to the Company's Service Schedules. APS accepts most of Staff's recommendations regarding Schedule 1 charges, but disagrees with Staff's position on APS' Line Extension Policy. APS also accepts many of Staff's recommended changes to the language found in the other Service Schedules. I have summarized the proposed revenue impact due to the acceptable changes to Service Schedule 1 and summarized the Schedule 1 language changes in Schedule DJR-1RB. Schedule DJR-2RB summarizes the changes in all other service schedules.

Finally, my Rebuttal Testimony includes proposed Plans of Administration for each of the adjustment mechanisms that were approved, as modified, in Docket No. E-01345A-02-0403 after the rate case Application was filed. These adjustment mechanisms include the Power Supply Adjustment (PSA) charge as described by

APS witness Donald Robinson, the Competition Rules Compliance Charge (CRCC), the Returning Customer Direct Assignment Charge (RCDAC), and the System Benefit Adjustment Charge (SBAC) that will be used to recover costs associated with demand side management programs and bark beetle remediation programs. A Plan of Administration for the proposed Transmission Cost Adjuster has also been included. I also provide proposed tariff sheets and a Plan of Administration for the new Environmental Portfolio Standard charge that is discussed by APS witness Edward Fox.

III. GENERAL SERVICE RATE SCHEDULES

Q. PLEASE DESCRIBE THE GENERAL SERVICE RATE SCHEDULE CHANGES THAT ARE PROPOSED BY THE OTHER PARTIES IN THIS CASE.

A. In general, each intervenor witness proposes changes that would shift revenue requirements from their constituency to some other customer group. Staff also proposes changes that would shift revenue requirements. Most intervenor recommendations would have residential customers assume a larger portion of APS' requested increase in revenue. Intervenor witnesses also offer revisions to specific rate elements of the general service rates.

Q. SEVERAL OF THE WITNESSES CONCLUDE THAT APS IGNORED BONBRIGHT'S RATEMAKING PRINCIPLES. DO YOU CONCUR WITH THAT ASSESSMENT?

A. Absolutely not. The application of Bonbright's principles is addressed in Mr. Propper's testimony in general terms, and specifically as applicable to residential customers. Bonbright's principles, as described by Mr. Propper, were also applied in the design of the general service rate schedules.

Q. CAN YOU EXPLAIN HOW BONBRIGHT'S PRINCIPLES WERE FOLLOWED IN THE DESIGN OF GENERAL SERVICE RATES?

A. Two of the key issues that APS addressed in the redesign of Schedule E-32 were simplicity and understandability. The current rate design of Schedule E-32 had evolved over many decades, beginning when "APS" was actually comprised of several companies. The last major revision of this schedule took place in 1985. Iterative changes to that schedule over many years have caused the rate to be overly complex and unnecessarily difficult to understand. The E-32 rates proposed by APS in this rate case reflect increased simplicity and understandability by reducing the number and type of billing blocks and eliminating demand charges for customers whose load is 20 kW and under.

We also attempted to improve the efficiency and effectiveness of the rates considerably. For example, our proposed rate design has the goal of improving price signals by recognizing the importance of load factor. Improved load factor is a metric that reflects efficient utilization of assets, and load factors were recognized by increasing the effective demand charge found in the rate. Compared to current rate designs, customers with a low load factor will see higher increases in average cost per kWh than customers with a high load factor. The increased demand charge and change in the design of rate blocks provide price signals to customers that indicate that capacity conservation through load management can result in lower bills.

Q. DID YOU CONSIDER OTHER TYPES OF RATE DESIGNS IN DEVELOPING SCHEDULE E-32?

A. Yes, we considered other rate concepts including a very simple structure in which customer costs would be recovered through a customer charge, capacity costs through a demand charge, and energy costs through an energy charge.

Q. WHY WAS THAT SIMPLE STRUCTURE NOT PROPOSED?

A. Moving from the current rate structure to the simple one outlined above would have resulted in significant rate dislocation—dramatic rate swings—for many customers. Our proposed design, however, moves closer towards such a simple structure while still recognizing the importance of load factor in cost recovery.

Q. PLEASE COMMENT ON STAFF WITNESS ANDREASEN'S TESTIMONY REGARDING THE GENERAL SERVICE RATE SCHEDULES.

A. Except for issues related to basic service charges, Ms. Andreasen is generally supportive of the proposed changes to APS' general service schedules. However, I disagree with her recommendation that there be no change to the current basic service charges.

Q. WHY DO YOU DISAGREE WITH MS. ANDREASEN'S RECOMMENDATION TO LEAVE BASIC SERVICE CHARGES UNCHANGED?

A. Staff's recommendation, found in the Direct Testimony of Ms. Andreasen, to leave basic service charges unchanged forecloses necessary differentiation in customer-related costs for secondary, primary, and transmission customers served under the General Service rates. For example, APS has proposed voltage level discounts to demand (kW) charges for primary and transmission level customers. However, to take primary or transmission services, a customer must have a different and more costly metering setup because of the need to install potential transformers. A primary distribution voltage metering set costs from $3,500 to $4,600 compared to $500 for a secondary meter set. Transmission level metering sets are considerably more expensive than even the primary sets, because each transmission level metering set must be engineered for a particular usage. As a result of these higher meter costs, it is not appropriate to offer a discount on $/kW to primary and transmission customers but not charge these same customers for the specialized metering through the metering component of the basic service charge. In other words, secondary customers should not be required to subsidize primary and transmission customers' metering costs, which would be the consequence of Staff's proposal to leave the basic service charge unchanged.

Q. PLEASE COMMENT ON MR. HIGGINS' TESTIMONY THAT PERTAINS TO THE GENERAL SERVICE RATE SCHEDULES.

A. In general, I believe Mr. Higgins supports the proposed design of Schedule E-32, although he disagrees with the overall revenue level and proposed rate increase spread across APS' customer classifications. For, example, he agrees with the proposal to provide voltage level discounts but disagrees with the rate schedule language which indicates that a transmission level customer would pay "distribution" charges.

Q. DO YOU AGREE WITH HIS COMMENTS REGARDING DISTRIBUTION CHARGES FOR TRANSMISSION CUSTOMERS?

A. I believe that Mr. Higgins' concern is based on the specific choice of words found in the proposed rate schedule rather than the nature of the charge itself. The language he refers to indicates that a transmission customer would pay "distribution charges." However, the use of the term "distribution" on the rate schedule may not accurately convey the intended meaning. What is labeled a "distribution" charge is in reality delivery service revenue requirement that must be recovered from all customers regardless of delivery voltage. I believe that Mr. Higgins' concern could be addressed by simply replacing "distribution" with "delivery" in the rate schedule, which could be done in a compliance filing in response to the Commission's final order in this proceeding.

Q. HAS MR. HIGGINS PROPOSED ANY OTHER CHANGES IN THE DESIGN OF SCHEDULE E-32?

A. Yes, he has proposed that the "break point" in the E-32 demand charge be lowered to 100 kW from the 500 kW that was proposed by APS. This change would spread proposed revenue increases away from mid-sized general service customers.

Q. DO YOU CONCUR WITH HIS RECOMMENDATION?

A. I believe Mr. Higgins' proposal has merit, and APS has no objection to implementing such a change. This change would also address a rate design issue expressed by Mr. Baron, concerning costs incurred to serve general service customers over 100 kW. However, implementing Mr. Higgins' proposal will require some other changes in Schedule E-32 to ensure that rate transitions are satisfactory and revenue requirements are met. Specifically, the changes would consist of adding an additional energy block to a portion of the rate schedule that is applicable to customers whose load is 20 kW and under.

Q. PLEASE DESCRIBE WHAT YOU MEAN BY RATE TRANSITIONS.

A. One of the desirable elements in designing rates is having smooth transitions as a customer's load changes. In our rate design, there are two locations where smooth transitions should occur. The first transition should occur at the point when a customer's load exceeds 20 kW, which is the point where customers start to require three-phase service and where metering requirements under the Competition Rules change. The second transition should occur when the customer's load exceeds 3 MW, and the customer shifts from Schedule E-32 to Schedules E-34 or E-35. The rate designer's objective is to design a rate so that the customer's bill does not change dramatically when these transition points are reached.

Q. DO YOU BELIEVE THAT THE RATE TRANSITION ISSUES CAN BE SOLVED?

A. I believe we can address Mr. Higgins' concern in the final rate design that will be developed when the Commission determines APS' test year revenue requirement. Schedule DJR-3RB, attached to this testimony, compares the rate schedule elements contained in the APS filing with an illustrative rate design that reflects the concepts that I just discussed. This illustrative rate design produces the same revenue as the Schedule E-32 rates originally filed by APS.

Q. PLEASE COMMENT ON MR. HIGGINS' CONCERN REGARDING APS' PROPOSED CHANGE TO SCHEDULE E-35.

A. Mr. Higgins' expressed concern over the Company's proposal to change the beginning of on-peak usage time from 11:00 AM to 9:00 AM. He indicated that one of his clients, Honeywell, had made operational changes based on the existing on-peak hours and that no change should be made in the on-peak hours found in Schedule E-35.

Q. WHY DID APS PROPOSE TO CHANGE THE HOURS?

A. The Company desired to adopt uniform on- and off-peak hours and billing seasons across all of our time-of-use rate schedules. Examination of the load characteristics of APS' system demonstrates that the load begins to rise rapidly after 8:00 AM, especially during the summer months. Schedule E-35 and other general service time-of-use rates, do not have the peak period commencing until 11:00 AM compared to 9:00 AM for residential time-of-use rates. It would be most desirable to begin the on-peak time period earlier in the day when load begins to increase rapidly.

Q. DID YOU TAKE THIS INCREASE IN THE NUMBER OF ON-PEAK HOURS INTO ACCOUNT IN YOUR PROPOSED RATES?

A. Yes, we did. We adjusted the billing determinants used to develop rates to reflect the new on-peak hours. We have also looked at the load characteristics of each E-35 customer. In some cases, the change in on-peak hours would not make a difference in the peak demand that is used for billing determinants. However, APS does not object to maintaining the current on-peak time periods in a revised Schedule E-35, given Mr. Higgins' testimony about how customers have made operational commitments based on the Company's existing on-peak designation. If this change is adopted, the charges found in the APS proposed Schedule E-35 will need to be modified to reflect the reduced on-peak hours. Also, APS would have to modify the on-peak time periods in Schedule E-32 TOU so the periods will be the same as Schedule E-35. Thus, the E-32 TOU hours would also be 11:00 AM to 9:00 PM.

Q. PLEASE COMMENT ON MR. BARON'S TESTIMONY REGARDING THE DESIGN OF RATE SCHEDULE E-32.

A. Mr. Baron comments that APS did not recognize a "discount" for customers who receive secondary voltage delivery but whose service is connected directly to a distribution transformer. Mr. Baron notes that those customers do not utilize the secondary system of APS.

Q. DO YOU AGREE WITH MR. BARON'S COMMENTS REGARDING SECONDARY SERVICE?

A. In general, I do. Many, but not all, customers whose load exceeds 100 kW will take service directly from a distribution transformer. To a certain degree, whether a customer is connected directly to a transformer or receives service from a secondary system is a function of location. Our Customer Information System does not contain data that enables us to isolate customers who receive secondary service directly from a transformer from customers who utilize the secondary system. Therefore, we cannot directly implement a secondary service discount as Mr. Baron proposes.

Q. DO YOU HAVE A SUGGESTED METHODOLOGY FOR ADDRESSING MR. BARON'S CONCERN?

A. Yes, as noted in my comments regarding Mr. Higgins' testimony, we have developed an alternative rate design that has a demand break point at 100 kW.

Q. DOES THE ALTERNATIVE DESIGN INCLUDE THE $0.94/KW DISCOUNT AS PROPOSED BY MR. BARON?

A. No, not directly as a "discount." Instead, the rate for customers with loads over 100 kW has been adjusted by adding a demand billing block for loads between 100 kW and 500 kW with a lower demand charge. This reaches the same result through rate design rather than through a $/kW discount. As shown in Schedule DJR-3RB, the added billing block necessitated increasing the demand charge for customers with demand meters whose load is less than 100 kW and increasing the energy-based charges for customers whose load is 20 kW or less.

Q. PLEASE COMMENT ON MR. FULMER'S TESTIMONY REGARDING RATE DESIGN FOR COMMERCIAL AND INDUSTRIAL CUSTOMERS WITH PEAK LOADS GREATER THAN 250 KW.

A. Before responding, I would note that Mr. Fulmer's recommendations are really a request to make significant changes to the Commission's Competition Rules, and should be addressed outside APS' rate case in a generic manner. Essentially, Mr. Fulmer recommends that the generation-related portion of APS' General Service rates applicable to customers with loads greater than 250 kW be based on APS' short-term procurement costs. Mr. Fulmer provides no evidence as to the derivation of his suggested 250-kW breakpoint other than it equates to approximately 22% of APS' annual energy sales. He also provides no evidence as to why the generation component for customers at that breakpoint should be based on short-term costs. This recommendation certainly does not provide the correct price signal to customers. Also, despite Mr. Fulmer's opinion, APS has the long-term obligation to provide cost-effective, reliable service to all General Service customers taking Standard Offer service in our service territory. The generation-related portions of APS unbundled General Service rate schedules reflect this obligation and provide an appropriate price signal for our customers.

Q. PLEASE COMMENT ON THE TESTIMONY OF MR. MURPHY.

A. Mr. Murphy essentially proposes to eliminate demand charges from Schedule E-32. In his testimony, he argues that APS' rate design does not comport to Professor Bonbright's rate design principles. In fact, APS always considers the Bonbright principles in designing rates, as noted by Mr. Propper in his rebuttal and as I have previously discussed. Interestingly, Mr. Murphy's own testimony selectively applies these principles, makes unpersuasive arguments regarding rate design, and then simply neglects to fully address the issue of cost causation.

Q. PLEASE ILLUSTRATE WHERE MR. MURPHY'S SUGGESTIONS VIOLATE BONBRIGHT'S PRINCIPLES.

A. One of the principles espoused by Bonbright is revenue stability. Mr. Murphy suggests that the elimination of demand charges will somehow result in revenue stability. In fact, energy-based rates are far less stable than cost-based rates with customer, capacity, and energy elements. APS' energy sales are quite weather dependent due to air-conditioning loads. Thus, contrary to Mr. Murphy's suggestion, relying on energy sales for cost recovery is inherently unstable. Mr. Murphy also fails to recognize that most of the costs incurred by APS are not energy based. The energy cost component (fuel and power purchases) of APS' revenue requirement amounts to approximately 27% of the total cost of providing service. Collection of fixed costs (the capacity costs of generation, transmission and distribution) should be capacity based (collected through demand charges) to provide the correct price signals to customers and to ensure revenue stability. Mr. Murphy's testimony also focuses on generation capacity costs and ignores the costs of delivery. These costs, of course, have virtually no energy element, and Mr. Murphy fails to recognize the impacts of incremental cost recovery. That is, if all costs are recovered through flat energy charges, incremental costs cause significant revenue stability issues. For example, if a utility sets cost recovery based on an 8.0 cent per kWh flat retail rate but energy sales drop off due to cool weather, the utility would lose the full 8 cents of revenue but may only see 4 cents per kWh decrease in costs due to avoided power purchases. The other 4 cents of costs (fixed cost elements) would be incurred but not recovered. And, this change is symmetrical in that if extraordinary hot weather occurs, over-collection by 4 cents per kWh could occur.

Q. IN YOUR OPINION, DOES MR. MURPHY'S PROPOSAL FOR ENERGY-ONLY BASED RATES VIOLATE ANY OTHER OF THE BONBRIGHT PRINCIPLES?

A. Yes, a radical change from the existing E-32 structure to an energy-based structure violates the concept that customers should experience rate stability. If APS moved from a demand-energy based structure to an energy-only structure, the likely result would be that low-load factor customers would see significantly lower bills and high-load factor customers would bear the additional revenue responsibility and see significantly higher bills. That is exactly opposite of what should occur in a capital-intensive industry like the electric utility sector.

Q. MR. MURPHY ARGUES FOR RATE SIMPLICITY. DO YOU CONCUR THAT RATE SIMPLICITY IS A POSITIVE ATTRIBUTE?

A. Yes, to the degree that you can have simple rates that also reflect cost causation. This is, however, a difficult balance to achieve. I believe APS' proposed rate schedules are a reasonable and appropriate step forward in achieving the correct balance. For example, for customers whose load is less than 20 kW, we have developed a simple, energy-based rate. These customers often have small loads, such as billboard lighting, signal lighting, or timers and can do little to manage demand. So an energy-based rate for these customers is simple, yet is still designed to address cost causation.

Q. PLEASE COMMENT ON THE TESTIMONY OF DR. GOINS.

A. Dr. Goins recommends that the proposed transmission voltage discount be reduced from $4.18 per kW to $3.30 per kW, and the primary discount be increased from $0.69 per kW to $1.40 per kW. While APS agrees with his methodology to determine the costs associated with voltage differentials, APS disagrees with his recommendation. APS' proposed discounts are based on its cost-of-service study. In contrast, Dr. Goins' recommendations are not even based on his own cost calculations. Dr. Goins states that APS did not provide support for its proposed primary and secondary discounts. This is simply not accurate. APS provided workpapers on point in response to an FEA data request. Also, unbundled functional revenue requirements, the basis for the discounts, were included in Mr. Propper's filed workpaper AP-WP3. Furthermore, support for the discounts was also provided in APS' response to Kroger's data requests 1-1, 1-2, and 3-1, which were also provided to the FEA.

Dr. Goins' recommendations regarding the level of voltage discounts that would be in rates appear to have been influenced by a desire to reduce the likelihood that transmission voltage customers would experience a rate decrease. As we move to more cost-based unbundled rates, decreases to some customers are an acceptable outcome. Rate redesign is a zero sum game. If charges to some customers increase, charges to other customers must decrease if the same target revenue level is to be achieved. Dr. Goins' workpapers provided in response to an APS data request show that he proposes that the discounts include an "adder," using his words. It appears that the sole function of this "adder" is to reduce the discount to transmission customers and increase the discount to primary customers without regard to cost justification. APS disagrees with inclusion of this "adder" because the voltage differential should be cost based.

Q. DR. GOINS RECOMMENDS INCREASING THE PEAK AND OFF-PEAK ENERGY CHARGE DIFFERENTIAL IN E-35. DO YOU AGREE WITH HIS RECOMMENDATION?

A. The price differential proposed by APS was based on a review of energy price differentials in the wholesale power marketplace and our proposed revenue targets. Dr. Goins' proposal is based on current rate differentials. I believe that the combination of increased on-peak demand charges and some differential level in energy charges provides appropriate price signals to encourage customers to shift loads to the off-peak periods.

Q. DR. GOINS PROPOSES MAINTAINING THE CURRENT SUMMER AND WINTER MONTHS AND TIME-OF-USE PERIODS FOR E-35. FURTHER, DR. GOINS QUESTIONS WHETHER APS HAS PROPERLY ACCOUNTED FOR THE INCREMENTAL REVENUE INCREASE ASSOCIATED WITH EXPANDING THE TIME-OF-USE ON-PEAK PERIOD. DO YOU AGREE WITH HIS RECOMMENDATIONS AND CONCLUSION?

A. Regarding the definition of summer months, I believe Dr. Goins' data supports APS' proposal to include May as a summer month. Table 1 in his direct testimony shows that May's ratio of monthly peak MW demand to annual maximum MW demand (86%) is higher than the ratio for October (66%), which is a summer month under the current E-35 rate design. Regarding the issue of the redesign associated with the expanding the time-of-use on-peak period, APS has adjusted billing determinants to account for the redefined on-peak period. However, as noted earlier in my testimony, APS is not opposed to Mr. Higgins' proposed change in on-peak hours. The attached worksheet, Schedule DJR-4RB compares the on- and off-peak kWh billing determinants for the current 11:00 AM to 9:00 PM on-peak period with the 9:00 AM to 9:00 PM billing period. Changing the proposed on-peak hours will require adjustments to the proposed energy charges to ensure proper revenue recovery.

IV. <u>SERVICE SCHEDULES</u>

A. Schedule 1

Q. DO YOU AGREE WITH STAFF WITNESS KEENE'S TESTIMONY REGARDING SERVICE SCHEDULE 1?

A. Although Ms. Keene has proposed Schedule 1 charges that are different than those I proposed in my direct testimony, APS finds many of her suggestions acceptable. Schedule DJR-1RB compares the Schedule 1 charges as originally proposed by APS with the charges recommended by Ms. Keene and charges which reflect a reasonable compromise between the two. I have also summarized the revisions to Schedule 1 in Schedule DJR-1RB

In general, Ms. Keene is recommending that APS' Schedule 1 charges be cost based. Cost-based pricing was also the objective in the charges proposed by APS. Ms. Keene is also recommending that APS continue to have provisions to accept letters of credit, as well as proposing some minor wording changes to require written notification to a customer before we disconnect service for failure to provide access, and of violations when customers create hazards to or obstructions of easements.

Q. DO YOU AGREE WITH MS. KEENE'S RECOMMENDATIONS ON THE PROPOSED CHARGES?

A. APS is willing to accept Ms. Keene's recommendation to make these proposed charges more cost-based in this rate proceeding, as long as this philosophy is consistently applied to all the proposed changes. Ms. Keene proposes cost-based charges unless the increase is larger than 15%. At that point, she recommends capping the increase to 15%. However, Ms. Keene provided no evidence to support this ceiling for the charges at issue in Schedule 1, and I believe a ceiling is unreasonable for several reasons. First, most of these charges have not been modified in over 10 years. APS is only trying to bring the charges to a current cost basis. Second, <u>all</u> of these charges are for optional services, and no customer is required to take <u>any</u> of these services. Therefore, if the customer finds the charge objectionable, the customer can select other alternatives. APS is merely trying to charge customers who request a special service a cost-based rate to prevent subsidization by the rest of our customer base. Finally, these charges tend to be one-time charges and are not additive in nature. As a result, "rate shock" is not an issue and the proposed charges are not cumulative. In fact, most customers will never need the special services that we are discussing, and for those that do require the special services, it will likely be a one-time occurrence. These charges should therefore be examined in a very different context than for non-optional, recurring charges for electric service that apply to more customers.

Q. PLEASE IDENTIFY THE SCHEDULE 1 CHARGES FOR WHICH YOU CAN ACCEPT MS. KEENE'S RECOMMENDATIONS.

A. APS can accept the recommendations for 1) the Trip Charge, 2) the After Hours Service Establishment Charge, 3) the On-site Energy Evaluation Charge, 4) the Joint Site Meetings Charge, and 5) the Reread Charge. APS also agrees with Ms.

Keene's recommendations concerning written notices for violations found in Sections 5.4 and 5.5.2 of Schedule 1.

Q. WHY DO YOU DISAGREE WITH MS. KEENE'S RECOMMENDATION FOR THE "AFTER HOURS OTHER SERVICES" CHARGE?

A. As Ms. Keene notes, the services being provided under this proposed charge are more complicated and time consuming than our regular service activities. A customer requesting more complicated and time consuming service to be done outside of normal work hours should bear the cost of the requested service. I do not believe that all customers should bear the additional cost involved in providing optional customer-requested services to a specific customer. Yet this is exactly what would occur if APS instituted Ms. Keene's proposed $75 flat charge, which understates the true cost of this service. Ms. Keene also states the charge should be fixed so the customer knows what the charge will be in advance. To address that concern, APS would agree to adding language that states "APS is to provide an estimate to do the work after hours, and the customer may choose to pay the charge or wait until normal work hours." Providing an estimate will allow the customer to know the expected charge in advance and base their decision on this information and is typical of the practice for other consumer services. The customer will pay the actual charges after the requested work is completed.

Q. DO YOU HAVE ANY COMMENTS ON MS. KEENE'S RECOMMENDATION FOR THE OVERHEAD AND UNDERGROUND RECONNECT CHARGES?

A. APS did not propose any change to the Underground Reconnect Charge and does not agree with the recommendation to reduce the charge by $10. In evaluating our proposed changes we compared current charges to costs and if the differential was small, we elected to propose no changes. In the case of the Underground Reconnect Charge, the cost analysis indicated a cost of slightly more than $116.

The existing charge is $125, so no change was proposed. I expect that with typical inflation in the cost of labor and services this differential will be absorbed relatively quickly, and $125 is a satisfactory approximation of the cost of the service that can be used for a reasonable period without requiring updating. APS agrees with the recommendation concerning the Overhead Reconnect Charge. The cost for this service is $96.03 and the staff proposed charge is $96.50. These reconnect charges are only imposed if a customer is terminated at a pole or underground equipment due to a delinquent account.

Q. DO YOU HAVE ANY COMMENTS ON MS. KEENE'S RECOMMENDATION FOR THE METER TEST CHARGE?

A. APS accepts Ms. Keene's recommendation for the meter shop test charge of $30, but we do not agree with the recommendation that the field-test charge should be $50. As shown on DJR_WP1 which was provided to Staff with my direct testimony, field tests cost anywhere from $50 to $100 more than Staff's recommended $50 charge. If Ms. Keene believes these charges should be cost based, then the field test charge should be higher than $50. Averaging, which is a methodology that Ms. Keene used in developing her recommendation to the Joint Site Meeting Charge, the four field test charges ($83.99, $152.48, $96.40, and $122.87) would yield $113.94. Because APS has proposed something less than the average, and because Ms. Keene herself argues that these charges should be cost based, the proposed charge of $100 is reasonable. If the customer feels that the $100 charge is unreasonable, the customer has the option of accepting a meter shop test at $30. A cost-based charge will also discourage unnecessary meter test requests. Generally meter tests would not be a repeat service so rate shock is not an issue.

Q. DO YOU HAVE ANY COMMENTS ON THE REST OF THE RECOMMENDATIONS FOR SCHEDULE 1?

A. Yes. In Section 2.5.1.2, APS is not proposing to limit the options available to customers to avoid providing a deposit. Instead we are trying to offer an option that is more viable for most of our customers. As stated in my direct testimony, many utilities, including Salt River Project, have discontinued in most cases the practice of providing letters of credit to customers who are leaving their system. Thus, many customers coming to APS from Salt River Project or other utilities will not be able to obtain a letter of credit to provide to us. Also, more companies have adopted the practice of requesting a report from credit rating agencies. The proposed change will offer an option that is commonplace in the industry and reflects business practices already being utilized in the industry. To alleviate Ms. Keene's concern regarding the perceived conflict between the Commission's rules and the language proposed by APS, I suggest that the existing language regarding letters of credit be retained and an additional subsection (2.5.1.3) be added which states:

> Company receives an acceptable (as determined by the Company) credit rating for the Applicant from a credit rating agency utilized by the Company.

This proposed compromise will allow APS to offer four options to the customer in lieu of providing a deposit. The options are 1) have comparable service with the Company within the last two years with no delinquencies; 2) have an acceptable credit rating; 3) provide a deposit guarantee notification or a surety bond; and 4) provide the letter of credit.

Q. DO YOU CONCUR WITH MS. KEENE'S RECOMMENDATION REGARDING SECTION 6.2 OF SCHEDULE 1?

A. I am not sure if Ms. Keene is recommending that we replace the words "Load Serving ESP" with "Meter Service Provider" only in 6.2 or if she also meant for this to be replaced in 6.2.1, 6.2.2, and 6.2.3. If the recommendation is only to Section 6.2, APS agrees with this recommendation. However, if she intended for this to be replaced in the subsections as well, APS does not agree with the recommendation because this would restrict the ability of APS to work with the Load Serving ESP for transactions such as requesting a joint site meeting or obtaining lock ring keys on behalf of the MSP. Such coordination is necessary. Regarding Section 6.4, APS agrees with Ms. Keene's comment.

Q. DO YOU HAVE ANY OTHER COMMENTS ON SCHEDULE 1?

A. Yes. In reviewing testimony regarding Schedule 1, we realized a section found in the current version was inadvertently removed from the filed Schedule 1. The specific language that should be inserted as Section 5.6 of the Schedule 1 filed with the Application can be found in a Service Schedule Errata attached to my testimony as Schedule DJR-5RB.

Q. PLEASE COMMENT ON DR. STUTZ' RECOMMENDATIONS FOR SCHEDULE 1.

A. Dr. Stutz recommended that APS not be allowed to implement a Trip Charge and that all increases in current charges be capped at 15%.

Dr. Stutz recommends APS' proposed trip charge be rejected because it would be "unexpected" and an "adverse change." His argument regarding the Trip Charge is unsupportable because under his logic, a utility could never implement a new charge, no matter how reasonable, because it would be unexpected and adverse. This charge would be used only in those instances where a customer requests APS to connect service, and APS attempts to meet that obligation only to find the customer's meter is not accessible—which is a condition of service with which customers are required to comply. In fact, during the connect process, customers are asked if the meter is accessible and are told that we must have unassisted access to the meter. Under these circumstances, if the serviceman finds that the meter is not accessible for connecting service and APS must make a second attempt, it is more equitable to charge that particular customer for the second attempt rather than to apportion the costs to all other customers. The customer will not experience any "unexpected" or "adverse change" if they meet their obligation of ensuring the meter is accessible to APS.

Next, Dr. Stutz recommends all requested changes to existing charges be capped at 15%. A 15% cap flies in the face of cost-based rate-making, especially for charges for optional services. Under Dr. Stutz proposal, APS' cost recovery for these charges would remain below actual cost. As I discussed in response to Ms. Keene's comments, it is important to note that the customer has control over these charges. For example, in most instances, APS provides standard next day service. However, when a customer is insistent that we connect service on the same day they are making the request, or that we send a serviceman out that night, the customer makes the decision to pay the additional after hours charge, or avoid the charge and accept the next day service. APS is not forcing this charge on the customer. Another example cited by Dr. Stutz refers to a 300% increase in the meter test charge. Currently, APS has one meter test charge of $25. APS has proposed to separate this charge into those meters tested in the shop ($30) and those tested in the field ($100). As I mentioned in my rebuttal to Ms. Keene, the field test is more expensive. This is because on a field test meter personnel can only perform the one job and must wait while the meter is being tested. In contrast, tests performed in a shop environment provide for the efficiency of testing multiple meters simultaneously and allow the meter technician to perform other activities while the testing is in progress. The meter accuracy test itself will not yield any different results; it is simply a matter of customer choice. If the customer agrees to have the meter tested in the meter shop, they can reduce the charge to themselves. And, in both cases, if the meter test shows the meter to be outside of the +/- 3% accuracy range, there is no charge to the customer.

Throughout Dr. Stutz' testimony on rate design and to some degree the proposed Schedules, he refers to the Bonbright ratemaking principles of equity, efficiency, cost tracking, and customer acceptance. APS' proposed Schedule 1 changes meet these principles. Equity requires the fairness of apportioning costs, which requires cost-based charges which are proposed by APS. Efficiency is sending the customer a "price signal" which elicits an informed response. APS' proposals meet this principle by setting a cost-based price signal which a customer, through behavior, can control. Finally, there is customer acceptance. While this is probably the most elusive of the principles because of the vagaries of human nature, I think most customers would accept that the customer causing APS to incur the charge, either through choice or action, should pay the charge rather than burdening all other customers.

B. Schedule 3

Q. PLEASE SUMMARIZE THE TESTIMONY OF STAFF WITNESS KEENE AND RUCO WITNESS STUTZ REGARDING SCHEDULE 3?

A. Yes. APS proposes replacing the current 1,000-foot construction allowance with a cost allowance of $3,500. Ms. Keene's recommendation is to retain the current footage allowance and the current refund provisions. Dr. Stutz recommends approval of the allowance basis but disagrees on the size of the allowance. He also disagrees with APS' proposal that subdivision economic feasibility studies be conducted based on a dual-fuel assumption where applicable.

Q. DO YOU HAVE ANY COMMENTS REGARDING MS. KEENE'S RECOMMENDATION REGARDING SCHEDULE 3?

A. Ms. Keene provides no basis for her desire to keep the current policy. Thus, I can only assume that it is based on an "if it isn't broken, don't fix it" philosophy. However, I believe that the current policy is clearly "broken." It was developed many years ago before concepts such as retail competition were ever contemplated and unfairly shifts cost burdens caused by one customer to the rest of our customer base. APS' current 1,000 feet free allowance policy has been in place for more than 50 years and, for a number of years, served its purpose well. However, with rising costs, it is no longer equitable or efficient pricing to ask all other customers to pay for the cost of the particular customer extensions that have prompted APS to propose this change. In Ms. Keene's testimony, as well as testimony from other intervenors, it has been stated that the Company needs to apply certain rate-making principles. Among those mentioned have been the principles of cost-based charges, equity in the apportionment of costs, and efficiency in pricing. Ms. Keene's recommendation to make no changes to the free construction allowance found in Schedule 3 does not result in fair and equitable treatment for customers. The revised policy proposed by APS is consistent with the provisions that A.A.C R14-2-207.C.1. in that we will provide a "free equipment allowance" of $3,500 in lieu of the existing footage allowance.

Q. PLEASE COMMENT ON DR. STUTZ' PROPOSED CHANGE IN THE ALLOWANCE LEVEL AND HIS RECOMMENDATION REGARDING THE APS ECONOMIC FEASIBILITY STUDIES USED IN ADMINISTERING THE LINE EXTENSION POLICY.

A. Dr. Stutz agrees with the APS proposal to adopt a dollar allowance in lieu of a footage allowance and recommends a $6,500 allowance which is roughly the average between the average embedded distribution cost ($1,500) and the effective cost of our current policy ($10,000). In responding to Dr. Stutz' recommendation, it is important to recognize the cost differences associated with the installations of overhead and underground electric facilities and exactly which customers are affected in the context of our proposed $3,500 allowance. Today, even many rural extensions are installed underground. Our proposed allowance is only applicable to individual or small groups of individual permanent residential customers, not subdivisions. The total cost of the extension must be less than $25,000. Therefore, the proposed change would affect a small number of customers (approximately 1,800 customers in 2003) requiring a line extension that involves construction. Even with this proposed allowance, not all of the customers within this group would have to pay for their line extension. Of the 1,800 extensions requiring construction made in 2003, almost 700 customers who would have received a free extension under the current footage allowance would still receive a free extension under the $3,500 allowance. Additionally, close to another 700 in this group would pay less than $5,000 for their extension under the proposed dollar allowance. So, out of almost 1,800 extensions, approximately 78% would either receive a free extension or pay less than $5,000. The remaining 400 customers would also receive the proposed allowance, but their contribution would be more than $5,000. Keeping in mind the rate-making principles of cost causation, equity in apportionment of costs, and efficiency in pricing, this is not unreasonable. Dr. Stutz' recommendation is grounded in part on an existing practice that was established many years ago and does not reflect sound rate-making policy today.

Regarding APS' proposed change to the economic feasibility analysis for subdivisions, this is simply a change in how APS administers the study and does not violate either A.A.C. R14-2-207 or Commission Decision No. 54872. APS does not agree that calculating revenue based on the specific facts applicable to a particular development is in some way inconsistent with public policy or A.R.S. §

40-202(F). This statute simply states that for new residences a developer must install both electric and natural gas in and to the structure so the ultimate consumer can decide which energy source they want for each appliance. APS' proposal is not advocating in any way that homes be built all-electric. We are simply proposing that when APS calculates the anticipated revenue from a proposed subdivision as part of its economic feasibility analysis, the calculation should reflect the facts applicable to that development. To continue running all studies with a fictional assumption that every subdivision is all-electric systematically overstates the anticipated revenues. This overstating of revenues requires the developer to build fewer homes to be economically feasible, and shifts the actual cost of providing an extension to the subdivision onto all customers. Running a study based on the actual facts applicable to a subdivision will provide enhanced accuracy in collecting advances from the builders and reduce the burden on customers. In fact, running a study based on reality rather than fiction seems to be absolutely consistent with sound public policy.

C. Schedule 7

Q. PLEASE SUMMARIZE MS. KEENE'S TESTIMONY REGARDING SCHEDULE 7?

A. APS requested a change in Schedule 7 to reflect recent developments in metering technology and performance monitoring. Ms. Keene has recommended no changes be made to Schedule 7 at this time.

Q. DO YOU HAVE ANY COMMENTS REGARDING MS. KEENE'S RECOMMENDATION FOR SCHEDULE 7?

A. APS does not agree with Ms. Keene's recommendation. Ms. Keene provides no analysis for her recommendation, other than the conclusion that she believes that it is inconsistent with the Commission's rules. I disagree with her conclusion that the Company's plan for a meter testing and maintenance program is so rigidly circumscribed by Rule R14-2-209(E)(2) that it cannot accommodate developments in metering technology. Meter technologies change rapidly and have changed since this subsection was last revised. Today, in some cases, there is no way to calibrate or maintain a meter due to changed meter technologies and the use of solid state meters. For these meters that physically cannot be calibrated, the Company instead would monitor the performance of a group of like or similar meters. While the rule has certain minimum requirements for the plan to be prepared by APS, the rule does not prohibit recognizing that some technologies do not provide for calibration or maintenance for individual meters. Changing the wording in APS' plan to "performance monitoring" to reflect the current state of metering technology in no way contradicts the intent of the rule. It is far superior to Ms. Keene's apparent conclusion that APS should avoid an entire type of new metering technology, no matter how appropriate for and valuable to our customers, because the technology cannot satisfy a rigid and inflexible interpretation of a rule that merely requires APS to file a plan for a meter testing and performance program, which is exactly what we have done in this proceeding.

D. Schedule 10

Q. DO YOU HAVE ANY COMMENTS REGARDING MS. KEENE'S TESTIMONY FOR SCHEDULE 10?

A. Yes. In Section 3.6.1, Ms. Keene recommends changing the word "more" to "less." The only sentence in that section that uses the word "more" is:

> Interval Metering is required for all customers that elect Direct Access and reach a single site maximum demand in excess of 20 kW one or more times or annual usage of 100,000 kWh or more.

I do not agree with this change. Interval metering is not required for customers with annual usage less than 100,000 kWh. This word should remain "more." I believe that Ms. Keene's concern was raised as a result of a review of the red-lined version of the revised Schedule 10 which contained a typographical error that does not appear in the filed version.

In Section 4.2.1, APS will retain the wording "at rates approved by the ACC" for charges related to providing billing information as proposed by Ms. Keene. We also agree with Ms. Keene's recommendations for Sections 5.1.7, 8.15, and 8.16.1.3.

We disagree with Ms Keene's recommendation for Section 8.12.2 regarding the ownership of metering instrument transformers. This issue was raised with and analyzed by the Process Standardization Working Group ("PSWG") in 2000 and the final recommendation of the PSWG was that APS would have exclusive ownership of its current transformers ("CTs") and potential transformers ("PTs"). This was a unanimous decision among all the participants because it was a favorable rule for the customer. The requirement that a Direct Access customer own CTs and PTs can be a barrier to competition since it increases the initial out-of-pocket cost to a customer who wishes to access alternative generation suppliers. It is also appropriate to ensure that there is at least some utility-owned equipment used to provide Direct Access customer service to ensure continued Commission jurisdiction over system benefits and other charges on such customers. Because the PSWG has already resolved this issue, I do not understand why Ms. Keene opposes APS' proposal and believe the Company's original recommendation should be accepted by the Commission.

Q. DO YOU HAVE OTHER COMMENTS REGARDING SCHEDULE 10?

A. Yes. While reviewing Staff's comments, APS realized the version of Schedule 10 filed in this rate case inadvertently dropped the opening paragraph to Section 7.1.

The language which is to be restored is found in the errata provided in Schedule DJR-5RB.

V. ADJUSTMENT MECHANISMS

Q. HAS APS INCLUDED IN THIS CASE THE ADJUSTMENT MECHANISMS FILED IN DOCKET NO. E-01345A-02-0403?

A. Yes. APS is including the Power Supply Adjuster ("PSA"), Returning Customer Direct Assignment Charge ("RCDAC"), Competition Rules Compliance Charge ("CRCC") and the System Benefit Adjustment Charge ("SBAC"). I have included plans of administration for each of the charges and adjusters. The plans have been updated to reflect the changes approved by the Commission in Decision No. 66567, which was issued after this case was filed, and changes to the adjusters that we are proposing in response to the recommendations made by other parties in this case. A rate schedule for each of these adjustments was included in the Company's direct testimony.

Q. PLEASE DESCRIBE THE POWER SUPPLY ADJUSTMENT MECHANISM TARIFF SHEET AND PLAN OF ADMINISTRATION.

A. The tariff sheet (Schedule PSA-1) implements the power supply adjustment mechanism described in more detail by Mr. Robinson. As noted by Mr. Robinson, the revised PSA includes a sharing based incentive mechanism. The Plan of Administration provides a description of the mechanism along with sample calculations depicting the PSA methodology. The PSA rate schedule and Plan for Administration are found in Schedule DJR-6RB.

Q. PLEASE DESCRIBE THE RETURNING CUSTOMER DIRECT ASSIGNMENT CHARGE AND ANY CHANGES TO IT AS A RESULT OF THE COMMISSION DECISION?

A. The RCDAC is a special adjustment for customers (or aggregated groups) 3 MW or greater that want to return to Standard Offer service and for whom we have not planned resource acquisitions. This charge only applies in very limited circumstances. It was approved, with conditions, by Decision No. 66567. The RCDAC Plan of Administration is attached as Schedule DJR-7RB. It reflects the conditions in Decision No. 66567 that 1) the charge should specify that it only applies to customers, or aggregated customer groups, of 3 MW or greater; 2) customers who give the Company one year's advance notice before returning to Standard Offer service are not subject to the RCDAC; and 3) that the RCDAC tariff describe the types of costs that the customer may incur and a general framework on how the charges will be calculated. A revised RCDAC rate schedule is included to address these changes from Decision No. 66567.

Q. PLEASE DESCRIBE THE COMPETITION RULES COMPLIANCE CHARGE AND ANY CHANGES TO IT AS A RESULT OF THE COMMISSION DECISION?

A. The CRCC is the mechanism that is designed to collect the transition costs the Company has incurred to implement Direct Access. The CRCC also was approved in Decision No. 66567. No changes were required to the rate schedule provided in the Application, but the CRCC Plan of Administration is attached as Schedule DJR-8RB.

Q. HOW DO YOU RECOMMEND THAT THE COMMISSION ADDRESS APS' OR STAFF WITNESS KEENE'S PROPOSED DSM ADJUSTMENT MECHANISM?

A. If the Commission approves a DSM adjustment mechanism, APS recommends that it be included in the SBAC adjustment. The 1999 Settlement Agreement and Decision No. 66567 contemplated that the SBAC would be used for Commission approved system benefits programs. I believe that inclusion of APS' or Ms. Keene's proposal for an expanded DSM program, or an alternative DSM program approved by the Commission, fits within the intent of the SBAC. APS is also proposing that the SBAC include the recovery of costs associated with the bark beetle management program described by Mr. Robinson. A Plan of Administration for the SBAC is attached. Schedule SBAC-1 and the Plan of Administration are found in Schedule DJR-9RB.

Q. HAS APS INCLUDED IN THIS CASE ANY ADJUSTMENT MECHANISMS IN ADDITION TO THOSE FILED IN DOCKET NO. E-01345A-02-0403?

A. Yes, we requested the approval of a Transmission Cost Adjustment ("TCA") mechanism in the rate case Application and are proposing a new Environmental Portfolio Standard ("EPS") surcharge mechanism in response to the testimony of other parties in this case and the Commission's recent decision to increase the EPS goals. I will discuss the EPS mechanism in the next section of my rebuttal testimony.

Q. WHAT DID STAFF WITNESS LEE SMITH RECOMMEND REGARDING THE COMPANY'S TCA PROPOSAL?

A. She recommends three things. First, the Company should notify the Commission when it files a change in any of its OATT rates at FERC and supply the Director of the Utilities Division with a copy of the FERC filing. Second, the TCA should not take effect until the shortfall reflected in the Balancing Account reaches a trigger level that indicates a significant change. The suggested trigger level is 5% of the total retail transmission cost approved in this case. When this level is reached, the Company would file for Commission approval of a TCA rate. Third, Ms. Smith recommends that the Company file a TCA implementation plan for Commission approval within 120 days of the decision in this case.

Q. DO YOU AGREE WITH STAFF WITNESS LEE SMITH'S FIRST RECOMMENDATION?

A. Yes. The Company is certainly willing to provide the Commission with notice and a copy of any OATT related filings it makes at FERC.

Q. DO YOU AGREE WITH HER TRIGGER POINT RECOMMENDATION?

A. APS believes the 5% trigger mechanism is unnecessary and not supported. We have proposed a simple mechanism with an annual adjustment that would recover increased transmission costs that would occur with changes to the FERC-accepted OATT rates or after an RTO or similar organization is in operation. Either of these two events could result in a significant change in the transmission costs incurred by APS for Standard Offer customers.

Q. DO YOU AGREE WITH HER THIRD RECOMMENDATION?

A. In response to Ms. Smith's third recommendation, I have attached a proposed rate schedule and Plan of Administration as Schedule DJR-10RB. I think it would be most appropriate for the Commission to approve the plan for administration in this case, along with the rate schedule.

VI. <u>ENVIRONMENTAL PORTFOLIO STANDARD ADJUSTMENT MECHANISM</u>

Q. IS APS PROPOSING AN ADJUSTMENT MECHANISM FOR THE EPS SURCHARGE?

A. Yes. APS witness Ed Fox discusses in his rebuttal testimony the EPS funding shortfall that results from the current EPS surcharge, and the funding that is required for APS to meet the current EPS goals. If the Commission intends to require APS to comply or come closer to complying with the EPS goals, a new EPS mechanism is necessary to collect the additional required funding for the program. The attached draft rate schedule, EPS-2, has been designed to implement the EPS program as discussed by Mr. Fox. APS proposes that the existing EPS tariff sheet, Schedule EPS-1, be cancelled. However, as an alternative, it would be possible to redesign EPS-2 to supplement the existing EPS-1 if the Commission wished to take such an approach and leave the existing EPS-1 in place. The new rate schedule for EPS-2 and the Plan of Administration are attached as Schedule DJR-11RB.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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REVENUE IMPACT FROM PROPOSED SCHEDULE 1 CHANGES

Charge	Current	APS Proposed	YE 2002 Volume	Impact	Staff Proposed	Impact	Proposed APS Per Rebuttal	Impact	
Trip Charge		$ 17.50	1,050	$ 18,375.00	$ 16.00	$ 16,800.00	$ 16.00	$ 16,800.00	
After Hours Charge - Regular	$ 50.00	$ 75.00	1,198	$ 29,950.00	$ 75.00	$ 29,950.00	$ 75.00	$ 29,950.00	
After Hours Charge - Special		$ 150.00	65	$ 9,750.00	$ 75.00	$ 4,875.00	$ 150.00	$ 9,750.00	
TONP @ Pole	$ 87.50	$ 100.00	336	$ 4,200.00	$ 96.50	$ 3,024.00	$ 96.50	$ 3,024.00	
On-Site Energy Evaluations	$ 50.00	$ 90.00	297	$ 11,880.00	$ 82.00	$ 9,504.00	$ 82.00	$ 9,504.00	
Joint Site Meetings	$ 30.00	$ 70.00	-	$ -	$ 62.00	$ -	$ 62.00	$ -	
Meter Re-reads	$ 10.00	$ 20.00	268	$ 2,680.00	$ 16.50	$ 1,742.00	$ 16.50	$ 1,742.00	
Meter Test - Shop	$ 25.00	$ 30.00	81	$ 405.00	$ 30.00	$ 405.00	$ 30.00	$ 405.00	
Meter Test - Field	$ 25.00	$ 100.00	28	$ 2,100.00	$ 50.00	$ 700.00	$ 100.00	$ 2,100.00	
				$ 79,340.00		$ 67,000.00		$ 73,275.00	$ (6,065.00)
Red indicates a new charge									
Foregoing Paper bill (customer incentive)		$ 5.00	13,343	$ 66,715.00		$ 66,715.00		$ 66,715.00	
Annual savings to APS		$ 5.26	13,343	$ 70,130.81		$ 70,130.81		$ 70,130.81	
Net Benefit to APS				$ (3,415.81)		$ (3,415.81)		$ (3,415.81)	$ -
Total Pro Forma Adjustment from Schedule 1 changes				$ 82,755.81		$ 70,415.81		$ 76,690.81	$ (6,065.00)

Summary of Service Schedule 1 Changes

Schedule 1 Section	APS Proposed	Staff Proposed	RUCO Proposed	APS Rebuttal Position
2.2.1	Add a $17.50 Trip Charge when we have to make a second trip to connect service	Accepted concept but recommended charge be $16.00	Recommended against this charge	Accept Staff recommendation
2.2.2	Increase After Hours Service Establishment charge to $75 (from $50). Also add wording that this charge will apply to same day connects, regardless of time worked	Staff accepted	Recommended charge be increased to $57.50	Oppose RUCO recommendation which would make the charge below cost.
2.2.3	Add section to have a "special" after hours charge for customer requested work that is more involved than a meter set, meter read, or connect. Our proposal would have the charge be hourly	Accepted concept but recommended charge be fixed at $75.	No comments	Oppose the Staff recommendation. This should be an hourly charge. Indicated APS would add wording to give the customer an estimate prior to them scheduling the work.
2.5.1.2 (Proposed)	Add a condition that customer can establish credit, with no deposit, if we get an acceptable credit rating	Staff opposes change	No comments	Oppose the Staff recommendation. Should be added as an option for customers.
2.5.1.2 (Existing)	Delete condition to accept a letter of credit from another utility	Staff opposes change	No comments	Accept Staff recommendation to retain this option
4.5.1	Increase overhead reconnection for a non-pay shut off to $100 (from $87.50)	Recommended charge be increased to $96.50 and also recommended we decrease the underground reconnection fee to $115 (from $125) which we did not propose	Recommended increase to $100	Accepted Staff and RUCO recommendation for the overhead reconnection fee. Oppose the Staff's proposal on the underground fee. APS' current charge is slightly less than cost and will become closer to cost in a relatively short period of time.

Schedule 1 Section	APS Proposed	Staff Proposed	RUCO Proposed	APS Rebuttal Position
4.6	Increase on-site evaluation charge to $90 (from $50)	Recommended $82	Recommended $57.50	Accept Staff recommendation; oppose RUCO recommendation which would make charge below cost.
5.4	Add stronger remedy for failure to provide access and remove the grandfather clause	Agreed with concept suggested APS add language to provide written notice before disconnecting service	No comments	Accept Staff recommendation
5.5.2	Added a new section that Company will take whatever action is necessary to keep easements, right-of-way, company equipment, etc. safe from obstructions, hazards, etc.	Agreed with concept suggested add language that notification to the customer or their agent be in writing	No comments	Accept Staff recommendation
6.2.1	Replaces Load Serving Entity with ESP	Suggested we replace Load Serving ESP with Meter Service Provider	No comments	Accept Staff recommendation with clarification
6.2.3	Have one joint site meeting charge for metro and State of $70 for first 30-minutes and hourly after.	Recommends $62 for all areas and $53 per hours for anything over 30-minutes	No comments	Accept Staff recommendation
6.4	For non-metered services replaced wording that consumption would be calculated to say determined by company	No comments on this wording change, but suggested we change Load Serving ESP to Meter Reading Service Provider	No comments	Accept Staff recommendation
6.4.4	Increase meter reread charge to $20 (from $10)	Recommended $16.50	Recommended $11.50	Accept Staff recommendation. Oppose RUCO recommendation which would make charge below cost.

Schedule 1 Section	APS Proposed	Staff Proposed	RUCO Proposed	APS Rebuttal Position
6.5	Recommended separating the meter test charge ($25) into two categories – shop tests and field tests with the shop test charge $30 and the field test charge $100	Accepted the shop test charge. Recommended field test charge be $50	Recommends one charge at $28.75	Oppose Staff recommendation for the proposed field test charge. Staff's recommendation would make this charge below cost. Customer can choose meter shop test if they don't want to pay the higher field test charge. Oppose RUCO recommendation which would make charges below cost.

Summary of Service Schedule 3 Changes

Schedule 3 Section	APS Proposed	Staff Proposed	RUCO Proposed	APS Rebuttal Position
1	Change current practice of giving a footage allowance (1000' free) to a construction allowance ($3500)	Recommends retaining current conditions	Accepts concept, but recommends allowance be increased to $6500.	Oppose Staff and RUCO recommendations as not being reflective of current line extension trends and not being cost based.
1.3	Add language that extensions over the free limits will be non-refundable	Recommends retaining current conditions	No comments	Oppose Staff recommendation as not being reflective of current trends.
4.4	Change language which states extensions to real estate subdivisions will be not be differentiated between all electric or dual energy to say revenue will be calculated based on information provided by the developer	No comments	Recommends we retain current practice of calculating anticipated revenues as though the subdivision were all electric.	Oppose RUCO recommendation. This is not against public policy or A.A.C. or current Schedule 3 wording and would reflect realities of what is actually being installed.

Summary of Service Schedule 7 Changes

Schedule 7 Section	APS Proposed	Staff Proposed	RUCO Proposed	APS Rebuttal Position
General Plan	Wording change to move from testing to performance monitoring	Recommends we retain current wording.	No comments	Oppose Staff recommendation. APS position is this is not inconsistent with A.A.C.
1	Remove statistical formulas and add wording that meters will be grouped by like attributes and performance determined using weighted average	Recommends we retain current wording.	No comments	Oppose Staff recommendation. APS position is this is not inconsistent with A.A.C.
2	Add wording that performance will be monitored through Company's Metering and Billing Systems	Recommends we retain current wording	No comments	Oppose Staff recommendation. APS position is this is not inconsistent with A.A.C.
3	Minor wording change that we will monitor installations for accuracy and recalibrate as necessary	Recommends we retain current wording	No comments	Oppose Staff recommendation. APS position is this is not inconsistent with A.A.C.
4	Add wording that performance will be monitored through Company's Metering and Billing Systems	Recommends we retain current wording	No comments	Oppose Staff recommendation. APS position is this is not inconsistent with A.A.C.

Summary of Service Schedule 10 Changes

Schedule 10 Section	APS Proposed	Staff Proposed	RUCO Proposed	APS Rebuttal Position
3.6.1	Clarified when interval metering is required	Recommended one word be changed from "more" to "less"	No comments	Pointed out in rebuttal that this was incorrect on the red line copy, but not the non-red line copy.
4.2.1	Remove wording "at rates approved by Commission" in reference to Company providing usage data	Recommends we retain wording that we provide the data at rates approved by the Commission	No comments	Accepted Staff recommendation
5.1.7	Replace "MRSP" with Load Serving ESP or its MRSP	Recommends we retain original wording	No Comments	Accepted Staff recommendation
8.12.02	Wording change to indicate Company will retain ownership of all CTs, PTs and associated equipment	Recommends we retain current restrictions	No comments	Oppose Staff Recommendation. The PSWG gave approval of this and Staff should accept the PSWG decision.

E-32 - Proposed - As Filed (Bundled Rate)

E-32, kW <= 20			
Winter (Jan-Apr Nov-Dec)			
BSC - Self-Contained Meter	$	0.575	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
kWh	$	0.09095	per kWh
Summer (May-Oct)			
BSC - Self-Contained Meter	$	0.575	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
kWh	$	0.10095	per kWh
E-32 kW > 20			
Winter (Jan-Apr Nov-Dec)			
BSC - Self-Contained Meter	$	0.575	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
1st 500 kW	$	6.348	per kW
over 500 kW	$	4.618	per kW
1st 200 kWh/kW	$	0.07518	per kWh
over 200 kWh/kW	$	0.03290	per kWh
Summer (May-Oct)			
BSC - Self-Contained Meter	$	0.575	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
BSC - Transmission	$	22.42	per day
1st 500 kW	$	6.348	per kW
over 500 kW	$	4.618	per kW
1st 200 kWh/kW	$	0.08518	per kWh
over 200 kWh/kW	$	0.04290	per kWh
Primary and Transmission Discounts			
for E-32, kW <= 20:			
Primary Discount	$	0.00722	per kWh
for E-32, kW > 20:			
Primary Discount	$	1.590	per kW
Transmission Discount	$	4.600	per kW

E-32 - Illustrative Design - (Bundled Rate)

E-32, kW <= 20			
Winter (Jan-Apr Nov-Dec)			
BSC - Self-Contained Meter	$	0.575	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
kWh (1st 5000)	$	0.09432	per kWh
kWh (over 5000)	$	0.03932	per kWh
Summer (May-Oct)			
BSC - Self-Contained Meter	$	0.575	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
kWh (1st 5000)	$	0.10432	per kWh
kWh (over 5000)	$	0.04932	per kWh
E-32 kW > 20			
Winter (Jan-Apr Nov-Dec)			
BSC - Self-Contained Meter	$	0.575	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
1st 100 kW	$	6.929	per kW
next 400 kW	$	4.618	per kW
over 500 kW	$	4.618	per kW
1st 200 kWh/kW	$	0.06790	per kWh
over 200 kWh/kW	$	0.04157	per kWh
Summer (May-Oct)			
BSC - Self-Contained Meter	$	0.575	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
BSC - Transmission	$	22.42	per day
1st 100 kW	$	6.929	per kW
next 400 kW	$	4.618	per kW
over 500 kW	$	4.618	per kW
1st 200 kWh/kW	$	0.07790	per kWh
over 200 kWh/kW	$	0.05157	per kWh
Primary and Transmission Discounts			
for E-32, kW <= 20:			
Primary Discount	$	0.00295	per kWh
for E-32, kW > 20:			
Primary Discount	$	0.650	per kW
Transmission Discount	$	3.660	per kW

E-32TOU - Proposed - As Filed (Bundled Rate)			
Note: Peak period 9A-9P			
E-32, kW <= 20			
Winter (Jan-Apr Nov-Dec)			
BSC - Self-Contained Meter	$	0.600	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
kWh	$	0.09095	per kWh
Summer (May-Oct)			
BSC - Self-Contained Meter	$	0.600	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
kWh - on peak	$	0.11375	per kWh
kWh - off peak	$	0.09375	per kWh
E-32 kW > 20			
Winter (Jan-Apr Nov-Dec)			
BSC - Self-Contained Meter	$	0.600	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
BSC - Transmission	$	22.422	per day
1st 500 kW on-Peak	$	15.046	per kW
over 500 kW on-peak	$	13.316	per kW
Residual kW off-peak	$	6.783	per kW
All kWh	$	0.03290	per kWh
Summer (May-Oct)			
BSC - Self-Contained Meter	$	0.600	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
BSC - Transmission	$	22.422	per day
1st 500 kW on-Peak	$	15.046	per kW
over 500 kW on-peak	$	13.316	per kW
Residual kW off-peak	$	6.783	per kW
Peak kWh	$	0.04855	per kWh
Off Peak kWh	$	0.03855	per kWh
Primary and Transmission Discounts			
for E-32, kW <= 20:			
Primary Discount	$	0.00722	per kWh
for E-32, kW > 20:			
Primary Discount	$	1.590	per kW
Transmission Discount	$	4.600	per kW

E-32TOU - Illustrative Design - (Bundled Rate)			
Note: Peak period 11A-9P			
E-32, kW <= 20			
Winter (Jan-Apr Nov-Dec)			
BSC - Self-Contained Meter	$	0.600	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
kWh (1st 5000)	$	0.09432	per kWh
kWh (over 5000)	$	0.03932	per kWh
Summer (May-Oct)			
BSC - Self-Contained Meter	$	0.600	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
kWh (1st 5000/month) - on peak	$	0.11823	per kWh
kWh (over 5000/month) - on peak	$	0.06323	per kWh
kWh (1st 5000/month) - off peak	$	0.09823	per kWh
kWh (over 5000/month) - off peak	$	0.04323	per kWh
E-32 kW > 20			
Winter (Jan-Apr Nov-Dec)			
BSC - Self-Contained Meter	$	0.600	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
BSC - Transmission	$	22.422	per day
1st 100 kW on-peak	$	12.574	per kW
next 400 kW on-peak	$	10.263	per kW
over 500 kW on-peak	$	10.263	per kW
Residual kW off-peak	$	7.179	per kW
All kWh	$	0.04157	per kWh
Summer (May-Oct)			
BSC - Self-Contained Meter	$	0.600	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
BSC - Transmission	$	22.422	per day
1st 100 kW on-peak	$	12.574	per kW
next 400 kW on-peak	$	10.263	per kW
over 500 kW on-peak	$	10.263	per kW
Residual kW off-peak	$	7.179	per kW
Peak kWh	$	0.05781	per kWh
Off Peak kWh	$	0.04781	per kWh
Primary and Transmission Discounts			
for E-32, kW <= 20:			
Primary Discount	$	0.00295	per kWh
for E-32, kW > 20:			
Primary Discount	$	0.650	per kW
Transmission Discount	$	3.660	per kW

E-35 - Proposed - As Filed (Bundled Rate)			
Note: Peak period 9A-9P			
BSC - Self-Contained Meter	$	0.575	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
BSC - Transmission	$	22.422	per day
per kW	$	13.598	per kW
per kW Excess Off Peak	$	6.717	per kW
per kWh peak	$	0.03618	per kWh
per kWh off peak	$	0.02868	per kWh
Primary Discount	$	0.690	per kW
Transmission Discount	$	4.180	per kW

E-35 - Illustrative Design - (Bundled Rate)			
Note: Peak period 11A-9P			
BSC - Self-Contained Meter	$	0.575	per day
BSC - Instrument-Rated Meter	$	1.134	per day
BSC - Primary	$	2.926	per day
BSC - Transmission	$	22.422	per day
per kW	$	13.598	per kW
per kW Excess Off Peak	$	6.717	per kW
per kWh peak	$	0.03664	per kWh
per kWh off peak	$	0.02914	per kWh
Primary Discount	$	0.690	per kW
Transmission Discount	$	4.180	per kW

Arizona Public Service Company
Adjusted 2002 Test Year
E-32TOU kWh Billing Determinants

E32 TOU kW <= 20 Small GS	Billing Determinants 11A-9P On-Peak	Billing Determinants 9A-9P On-Peak
Summer (May-Oct)		
1st 5000 kWh/mo. - on peak kWh	96,181	116,210
Over 5000 kWh/mo. - on peak kWh	4,583	5,538
1st 5000 kWh/mo. - off peak kWh	264,392	244,363
Over 5000 kWh/mo. - off peak kWh	12,599	11,645
E-32 TOU, 20< kW < 100 Small GS		
Summer (May-Oct)		
peak kWh	5,621,234	6,739,729
off-peak kWh	12,994,661	11,876,166
E-32 TOU, 100 <= kW < 1000 Med GS		
Summer (May-Oct)		
peak kWh	12,700,272	15,239,635
off-peak kWh	29,940,054	27,400,690
E-32 TOU, kW >= 1000		
Summer (May-Oct)		
peak kWh	15,573,288	18,699,137
off-peak kWh	37,281,162	34,155,314

Note: Billing Determinants are based on summer period of May through October.

	Charge	11A-9P On-Peak Determinants	9A-9P On-Peak Determinants
E-35			
E-35	All On-Peak kWh	131,757,259	157,503,050
	All Off-Peak kWh	303,800,334	278,054,543
E-35 (1 Delivery Point; Tot. w/Chg)	All On-Peak kWh	54,151,219	64,320,027
	All Off-Peak kWh	119,991,942	109,823,134
E-35 (2 Delivery Points; Tot. w/Chg)	All On-Peak kWh	21,672,534	25,672,911
	All Off-Peak kWh	47,204,452	43,204,075
SPECIAL CONTRACTS			
Contract Cust (E-35 Charges)	All On-Peak kWh	83,026,033	109,357,333
	All Off-Peak kWh	310,709,337	284,378,037
Contract Cust (E-35 Charges)	All On-Peak kWh	12,934,358	15,529,073
	All Off-Peak kWh	30,617,642	28,022,927
Contract Cust (E-35 Charges)	All On-Peak kWh	30,499,665	36,501,291
	All Off-Peak kWh	70,819,190	64,817,564

SCHEDULE DJR-5RB

ERRATA

5.6 Load Characteristics – The customer shall exercise reasonable care to assure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in demand, shall not impair service to other customers or interfere with operation of telephone, television, or other communication facilities. The deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. In situations where Company suspects that a customer's load has a non-conforming power factor, Company may install at its cost the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a power factor of less than 90%, or leading, or other detrimental conditions, shall be required to remedy problems in order to achieve a power factor in conformance with above standards, or pay for facilities/equipment that Company must install on its system to correct for problems caused by Customer's load. Until such time as Customer remedies the problem, kVA may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

7.1 Subject to availability, and pursuant to the terms in the ESP Service Acquisition Agreement, this Schedule 10, and applicable tariffs and the restrictions therein, ESPs may select among the following billing options:

7.1.1 COMPANY UDC CONSOLIDATED BILLING
7.1.2 ESP CONSOLIDATED BILLING
7.1.3 DUAL COMPANY/ESP BILLING

1492959

Schedule DJR-6RB
Power Supply Adjustment Plan for Administration

Schedule DJR-6RB
Power Supply Adjustment Plan for Administration

General Description

The main components of the Power Supply Adjustment ("PSA") are: 1) a risk sharing mechanism whereby APS and its customers share in the costs/savings on a 90% customer, 10% APS basis with a maximum sharing amount of plus or minus $20 million for the Company; 2) a Bandwidth that limits the amount the Power Cost Component Factor ("PCCF") can change each year to plus or minus $0.004 per kWh; 3) includes Off-System Sales and; 4) a Balancing Account.

The results of the PSA are applied to customer's bills through the PCCF. The PCCF is applicable to APS' Standard Offer Rate Schedules (with the exception of solar and E-36 service) and is calculated annually. It is applied to the customer's bill as a monthly kilowatthour charge that is the same for all customer classes. The PCCF will be changed in billing cycle 1 of the April revenue month and it will not be prorated. The PCCF must remain within a Bandwidth that limits the amount it can increase or decrease each year. Amortization Charges are not included in the calculation of the Bandwidth limits.

Calculations

The PCCF shall be calculated as follows;

Part 1. Over/Under Collection

1. Sum the calendar year's Net Power Supply Cost to determine the Annual Net Power Supply Cost. The monthly Net Power Supply Cost is the Total System Book Fuel and Purchased Power Costs less the System Book Off-System Sales Revenue. The Off-System Sales Revenue includes only the off-system sales using APS owned, or contracted, generation and purchased power related to optimizing the APS system.

2. Sum the calendar year's Total Native Load Energy Sales (kWh) to determine the Annual Energy Sales.

3. Divide the Annual Net Power Supply Cost by the Annual Energy Sales to determine the Actual Average Power Supply Cost per kWh.

4. The Power Supply Cost Differential per kWh is calculated by subtracting the Base Rate Average Power Supply Cost per kWh from the Actual Average Power Supply Cost per kWh.

5. Sum the calendar year's Retail Energy Sales (kWh) to determine the Annual Retail Energy Sales.

6. The Total Over/Under Collection is determined by multiplying the Power Supply Cost Differential per kWh by the Annual Retail Energy Sales.

7. Directly-assigned power supply costs and related energy sales from existing Special Contract customers, Schedule E-36 customers and customers returning to Standard Offer service from competitive generation subject to RCDAC treatment will be deducted prior to the above calculations.

Part 2. Sharing Incentive

1. The Total Over/Under Collection Amount is then multiplied by 10% to implement the 90%/10% Sharing Incentive and determine the Calculated Company Share before the Sharing Cap.

2. The maximum amount for the Company Share is plus or minus $20 Million. The Applicable Company Share is determined by taking the lesser of the Calculated Company Share before the Sharing Cap and the plus or minus $20 Million cap.

3. The Post-Sharing Credit/Surcharge Amount is calculated by subtracting the Applicable Company Share from the Total Over/Under Collection.

4. If the PCCF Bandwidth (described below) allows for just a partial recovery of the Total Credit/Surcharge amount then the portion that is not eligible for crediting/collection in the current year is carried forward to next year as the Bandwidth Carry Forward from Prior Period.

5. The Interest on Bandwidth Carry Forward amount is calculated by multiplying the Bandwidth Carry Forward from Prior Period by the effective APS Deposit Interest Rate that the Company applies to customer deposits. The APS Deposit Interest Rate is the one year Treasury Constant Maturities rate, effective on the first business day of each year as published on the Federal Reserve Website.

6. Add the Post-Sharing Credit/Surcharge Amount, Bandwidth Carry Forward from Prior Period and the Interest on the Bandwidth Carry Forward together to determine the Total Credit/Surcharge Amount.

Part 3. PCCF and Bandwidth

1. The Computed PCCF is calculated by dividing the Total Credit/Surcharge Amount by the Projected Energy Sales (kWh) for the coming 12 months. The Computed PCCF is then compared to the plus or minus $0.004 per kWh Bandwidth.

2. To determine the PCCF Bandwidth Upper Limit, add $0.004 per kWh (4 Mills) to the Prior Year's Applicable PCCF.

3. To determine the PCCF Bandwidth Lower Limit, subtract $0.004 per kWh (4 Mills) from the Prior Year's Applicable PCCF.

4. If the Computed PCCF is inside the Bandwidth, the Computed PCCF becomes the Applicable PCCF. It is then applied to each month's bills for the next 12 months.

5. If the Computed PCCF is outside the Bandwidth, the Applicable PCCF can be no higher than the upper limit of the Bandwidth and no lower than the lower limit of the Bandwidth. For example, in the chart below the Computed PCCF of $0.01056 did not become the Applicable PCCF because it is greater than the Upper Bandwidth limit of $0.00965, so $0.00965 becomes the Applicable PCCF.

6. If the Computed PCCF is outside the Bandwidth then the Total Credit/Surcharge Carried Forward Due to PCCF Bandwidth amount must be calculated by multiplying the Applicable PCCF by the Projected Energy Sales (kWh) for the next 12 months and subtracting the total from the Total Credit/Surcharge Amount used to calculate the Applicable PCCF.

Examples of these calculations are attached as Schedules 1 and 2. Attached as Schedule 3 is a multi-year example illustrating a Bandwidth Carry Forward.

<u>Balancing Account and Amortization Charge</u>

APS shall establish a PSA Balancing Account ("Account"). Entries to the Account shall be made each month as follows:

1. A debit or credit entry equal to the difference between the Net Power Supply Cost incurred and the sum of the amounts recovered by both the Applicable PCCF and Base Rate Average Power Supply Cost.

2. A debit or credit entry equal to the kilowatthours billed for the month under the rate schedules subject to the PCCF multiplied by the effective Amortization Charge (as described below). If an Amortization Charge is not in effect then no entry will be made.

3. A monthly debit or credit entry for interest to be applied to the account balance based on effective APS Deposit Interest Rate that the Company applies to customer deposits.

4. A debit or credit entry for refunds or payments authorized by the Commission.

An example of the Balancing Account calculations is included as Schedule 4.

The Company can file a request with the Commission for approval of an Amortization Charge if the Account balance exceeds plus or minus $50,000,000. The Commission, after reviewing the application, may authorize the balance to be amortized and the time period of its recovery. If the Company files an Amortization Charge request, the charge will be calculated by taking the Balancing Account End of Month Balance and dividing it by the Company's estimate of the Total Retail Energy Sales for the filed amortization time period. This calculation yields a monthly kilowatthour charge that, if approved, is added to the customer's bills over the approved time period. These calculations will be filed with the Commission along with the request to implement the charge.

Filings

The PCCF and Balancing Account calculations and workpapers will be filed with the Commission annually. Workpapers and other documents that contain proprietary or confidential information will be filed with the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. All of the information is available during the year upon Commission request. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund if those costs are found to be imprudently incurred.

Allowable Costs

The allowable PCCF costs include fuel and purchased power costs incurred to provide service to retail customers. The Base Rate Average Power Supply Cost will be the allowable PCCF costs from the test year used to determine Standard Offer rates. The allowable cost components include but are not limited to the following Federal Energy Regulatory Commission ("FERC") accounts:

1. 501 Fuel (Steam)
2. 518 Fuel (Nuclear)
3. 547 Fuel (Other Production)
4. 555 Purchased Power

Directly Assignable Power Supply Costs

The May 17, 1999 Settlement Agreement and Decision No. 66567 from Docket No. E-01345A-98-0473 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS Standard Offer service, including Special Contract rates, for a competitive generation supplier and then return to Standard Offer service (for administrative purposes, customers who were Direct Access customers since origination of service and request Standard Offer service would be considered to be returning customers). In such cases, a direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the Returning Customer and the power supply cost component of the otherwise applicable Standard Offer rate. This process is described in the Returning Customer Direct Assignment Charge rate schedule and Plan for Administration.

In addition, if APS purchases power under specific terms on behalf of a Standard Offer Special Contract customer, the costs of that power may be directly assigned.

In both cases, where specific power supply costs are identified and directly assigned to a large Returning Customer or Standard Offer Special Contract customer or group of customers, these costs will be excluded from the PCCF calculations.

Schedule E-36 customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs are excluded from the PSA.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Example PSA Calculation Methodology

Line No.	Month	(a) Retail Energy Sales (kWh)	(b) Native Load Wholesale Energy Sales (kWh)	(c) Total Native Load Energy Sales (kWh)	(d) Total System Book Fuel and Purchased Power Costs	(e) System Book Off-System Sales Revenue	(f) Total Net Power Supply Cost
				(a +b)			(d - e)
1	January	1,963,130,000	14,210,000	1,977,340,000	$ 47,969,280	$ 19,289,000	$ 28,680,280
2	February	1,801,819,000	16,451,000	1,818,270,000	$ 40,807,680	$ 15,833,000	$ 24,974,680
3	March	1,712,984,000	14,840,000	1,727,824,000	$ 38,738,880	$ 13,319,000	$ 25,419,880
4	April	1,665,949,000	30,025,000	1,695,974,000	$ 43,948,800	$ 7,099,000	$ 36,849,800
5	May	1,844,862,000	41,471,000	1,886,333,000	$ 53,191,680	$ 13,202,000	$ 39,989,680
6	June	2,216,556,000	33,074,000	2,249,630,000	$ 63,962,880	$ 11,605,000	$ 52,357,880
7	July	2,615,184,000	40,929,000	2,656,113,000	$ 72,621,120	$ 7,295,000	$ 65,326,120
8	August	2,699,139,000	50,723,000	2,749,862,000	$ 73,295,040	$ 5,674,000	$ 67,621,040
9	September	2,575,503,000	48,814,000	2,624,317,000	$ 58,077,120	$ 5,336,000	$ 52,741,120
10	October	2,154,054,000	28,146,000	2,182,200,000	$ 53,153,280	$ 20,219,000	$ 32,934,280
11	November	1,768,036,000	21,562,000	1,789,598,000	$ 40,514,880	$ 21,537,000	$ 18,977,880
12	December	1,834,804,000	16,022,000	1,850,826,000	$ 51,711,360	$ 24,054,000	$ 27,657,360
13	Total	24,852,020,000	356,267,000	25,208,287,000	$ 637,992,000	$ 164,462,000	$ 473,530,000

Annual Net Power Supply Cost to move forward to Sch. 2.	$ 473,530,000
Annual Energy Sales to move forward to Sch. 2.	25,208,287,000
Annual Retail Energy Sales to move forward to Sch. 2.	24,852,020,000

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
Example PSA Calculation Methodology

Line No.				
	(Over)/Under Collection			
1	Annual Net Power Supply Cost (Sch. 1)	$ 473,530,000		
2	Annual Energy Sales (kWh) (Sch. 1)	25,208,287,000		
3	Actual Average Power Supply Cost per kWh (Line 1 / Line 2)	$ 0.018785		
4	Base Rate Average Power Supply Cost per kWh	$ 0.019839		
5	Power Supply Cost Differential per kWh (Line 3 - Line 4)		$ (0.001054)	
6	Annual Retail Energy Sales (kWh) (Sch. 1)		$ 24,852,020,000	
7	Total (Over)/Under Collection (Line 5 * Line 6)			$ (26,194,029)
	90/10 Sharing Incentive			
8	Total (Over)/Under Collection		$ (26,194,029)	
9	Company Sharing Percentage (10%) of Total (Over)/Under Collection		10%	
10	Calculated Company Share before the Sharing Cap (Line 8 * Line 9)		$ (2,619,403)	
11	Applicable Company Share (Lesser of Line 10 or plus/minus $20 Million)			$ (2,619,403)
12	Post-Sharing (Credit)/Surcharge Amount (Line 7 - Line 11)			$ (23,574,626)
13	Bandwidth Carry Forward from Prior Period			$ -
14	Interest on the Bandwidth Carry Forward (1.31% Cust. Dep. Rate)			$ -
15	Total (Credit)/Surcharge Amount (Line 12 + Line 13 + Line 14)			$ (23,574,626)
	PCCF Calculation			
16	Total (Credit)/Surcharge Amount	$ (23,574,626)		
17	Projected Energy Sales (kWh)	25,846,000,000		
18	Computed PCCF per kWh (Line 16 * Line 17)		$ (0.000912)	
	PCCF Bandwidth			
19	Prior Year's Applicable PCCF	$ -		
20	Bandwidth Amount	$ 0.004		
21	PCCF Bandwidth Upper Limit		$ 0.004000	
22	Prior Year's Applicable PCCF	$ -		
23	Bandwidth Amount	$ 0.0040		
24	PCCF Bandwidth Lower Limit		$ (0.004000)	
25	Applicable PCCF per kWh			$ (0.000912)
26	Total (Credit)/Surcharge Carried Forward Due to PCCF Bandwidth			$ -

Arizona Public Service Company
Schedule 3
Example PSA Calculation
Illustration of PCCF Charge Bandwidth

Line No.		Year 1	Year 2	Year 3	Year 4	Year 5
1	PCCF Bandwidth	Inside	Outside	Inside	Inside	Inside
2	Adjustment to Annual Energy Sales for this Example	N/A	KWH Increase 4%	KWH Increase 4%	KWH Increase 4%	KWH Increase 4%
3	Adjustment to Annual Power Supply Costs for this Example	N/A	Cost Increase 30%	Cost Decrease 15%	Cost Increase 4%	Cost Increase 4%
	(Over)/Under Collection					
4	Annual Net Power Supply Cost (Sch. 1)	$ 473,530,000	$ 615,589,000	$ 523,250,650	$ 544,180,676	$ 565,947,903
5	Annual Energy Sales (kWh) (Sch. 1)	25,208,287,000	26,217,000,000	27,266,000,000	28,357,000,000	29,491,000,000
6	Actual Average Power Supply Cost per kWh (Line 4 / Line 5)	$ 0.018785	$ 0.023481	$ 0.019191	$ 0.019190	$ 0.019191
7	Base Rate Average Power Supply Cost per kWh	$ 0.019839	$ 0.019839	$ 0.019839	$ 0.019839	$ 0.019839
8	Power Supply Cost Differential per kWh (Line 6 - Line 7)	$ (0.001054)	$ 0.003642	$ (0.000648)	$ (0.000649)	$ (0.000648)
9	Annual Retail Energy Sales (kWh) (Sch. 1)	24,852,020,000	25,846,000,000	26,880,000,000	27,955,000,000	29,073,000,000
10	Total (Over)/Under Collection (Line 8 * Line 9)	(26,194,029.08)	94,131,132.00	(17,418,240.00)	(18,142,795.00)	(18,839,304.00)
	90/10 Sharing Incentive					
11	Total (Over)/Under Collection	$ (26,194,029)	$ 94,131,132	$ (17,418,240)	$ (18,142,795)	$ (18,839,304)
12	Company Sharing Percentage (10%) of Total (Over)/Under Collection	10%	10%	10%	10%	10%
13	Calculated Company Share before the Sharing Cap (Line 11 * Line 12)	$ (2,619,403)	$ 9,413,113	$ (1,741,824)	$ (1,814,280)	$ (1,883,930)
14	Applicable Company Share (Lesser of Line 13 or +/- $20 Million)	$ (2,619,403)	$ 9,413,113	$ (1,741,824)	$ (1,814,280)	$ (1,883,930)
15	Post-Sharing (Credit)/Surcharge Amount	$ (23,574,626)	$ 84,718,019	$ (15,676,416)	$ (16,328,516)	$ (16,955,374)
16	Bandwidth Carry Forward from Prior Period	**$ -**	**$ -**	**$ 1,715,776**	**$ -**	**$ -**
17	Interest on the Bandwidth Carry Forward (1.31% Cust. Dep. Rate)	**$ -**	**$ -**	**$ 22,477**	**$ -**	**$ -**
18	Total (Credit)/Surcharge Amount	$ (23,574,626)	$ 84,718,019	$ (13,938,163)	$ (16,328,516)	$ (16,955,374)
	PCCF Calculation					
19	Total (Credit)/Surcharge Amount	$ (23,574,626)	$ 84,718,019	$ (13,938,163)	$ (16,328,516)	$ (16,955,374)
20	Projected Energy Sales (kWh)	25,846,000,000	26,880,000,000	27,955,000,000	29,073,000,000	30,236,000,000
21	Computed PCCF per kWh	$ (0.000912)	$ 0.003152	$ (0.000499)	$ (0.000562)	$ (0.000561)
	PCCF Bandwidth					
22	Prior Year's Applicable PCCF	$ -	$ (0.000912)	$ 0.003088	$ (0.000499)	$ (0.000562)
23	Bandwidth Amount	$ 0.004	$ 0.004	$ 0.004	$ 0.004	$ 0.004
24	PCCF Bandwidth Upper Limit	$ 0.004000	$ 0.003088	$ 0.007088	$ 0.003501	$ 0.003438
25	Prior Year's Applicable PCCF	$ -	$ (0.000912)	$ 0.003088	$ (0.000499)	$ (0.000562)
26	Bandwidth Amount	$ 0.004	$ 0.004	$ 0.004	$ 0.004	$ 0.004
27	PCCF Bandwidth Lower Limit	$ (0.004000)	$ (0.004912)	$ (0.000912)	$ (0.004499)	$ (0.004562)
28	Applicable PCCF per kWh	**$ (0.000912)**	**$ 0.003088**	**$ (0.000499)**	**$ (0.000562)**	**$ (0.000561)**
29	Total (Credit)/Surcharge Carried Forward Due to PCCF Bandwidth	**$ -**	**$ 1,715,776**	**$ -**	**$ -**	**$ -**

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
Example Balancing Account Calculations
December, XXXX

Line No.				
1	Beginning Balance			$ 22,672,375
2	Month's Net Power Supply Cost	$ 27,657,360		
3	Month's Total Energy Sales (kWh)	$ 1,850,826,000		
4	Month's Actual Average Power Supply Cost per kWh (Line 2 / Line 3)		$ 0.014943	
5	Base Rate Average Power Supply Cost per kWh	$ 0.019839		
6	Applicable PCCF	$ -		
7	Power Supply Cost per kWh in Rates (Line 5 + Line 6)		$ 0.019839	
8	Power Supply Cost Differential per kWh (Line 4 - Line 7)		$ (0.004896)	
9	Month's Retail Energy Sales (kWh)		1,834,804,000	
10	Total (Over)/Under Collection (Line 8 * Line 9)			$ (8,982,737)
11	Adjustments (if applicable)			$ -
12	End of Month Balance before Interest (Line 1 + Line 10, + or - Line 11)			$ 13,689,638
13	Monthly Interest (Line 1 * (1.31%/12))			$ 24,751
14	End of Month Balance (Line 12 + Line 13)			$ 13,714,389
15	Total Amount of Balance to be Amortized (if any)		$ -	
16	Adjusted End of Month Balance (Line 14 - Line 15)			$ 13,714,389
17	Total Amount of Balance to be Amortized from Line 15		$ -	
18	Estimated Retail Energy Sales for the next 12 months (kWh)		25,846,000,000	
19	Balancing Account Amortization Charge per kWh (Line 17 / Line 18)			$ -

APS

RATE SCHEDULE PSA-1
POWER SUPPLY ADJUSTMENT

APPLICATION

The Power Cost Component Factor (" PCCF") shall apply to all Standard Offer retail electric schedules, excluding those which are for solar and E-36 Station Use service. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

PCCF ANNUAL ADJUSTMENT

The main components of the Power Supply Adjustment ("PSA") are: 1) a risk sharing mechanism whereby APS and its customers share in the costs/savings on a 90% customer, 10% APS basis with a maximum sharing amount of plus or minus $20 million for the Company; 2) a Bandwidth that limits the amount the Power Cost Component Factor ("PCCF") can change each year to plus or minus $0.004 per kWh; 3) includes Off-System Sales and; 4) a Balancing Account. The calculation method is set forth in the filed Power Supply Adjustment Plan for Administration (the "Plan"). Standard Offer rate schedules covered by this charge include an Average Power Supply Cost ("APSC") of $X.XXXXXX per kilowatt-hour. In accordance with A.C.C. Decision No. XXXXX, an annual adjustment to the APSC will be made through a change in the PCCF that is based upon the twelve month totals of actual retail power supply costs and retail energy sales.

The PCCF is calculated annually and the total over/under collection balance, less the 90%/10% sharing, is collected over the next twelve months. The PCCF is applied to the customer's bill as a monthly kilowatthour charge and is the same for all affected Standard Offer customer classes. The PCCF will change in billing cycle 1 of the April revenue month and it will not be prorated. The PCCF must remain within the Bandwidth that limits the amount it can increase or decrease each year.

RATES

The charges shall be calculated at the following rates:

PCCF

All kWh	$0.000XXX	per kWh

Amortization Charge

All kWh	$0.000XXX	per kWh

AMORTIZATION CHARGE

The Company can file a request with the Commission for approval of an Amortization Charge if it believes the Account balance exceeds plus or minus $50,000,000. The Commission, after reviewing the application, may authorize the balance to be amortized and the time period of its recovery. If the Company files an Amortization Charge request the charge will be calculated by taking the End of Month Balance and dividing it by APS' estimate of the Total Retail Energy Sales for the filed amortization time period. This calculation yields a monthly kilowatthour charge that, if approved, will be added to the customer's bills over the approved time period. These calculations will be filed with the Commission along with the request to implement the charge.

INTEREST ON BANDWIDTH CARRY FORWARD FROM PRIOR PERIOD

If a carry forward is necessary (as described in the Plan) then the applicable interest rate is the effective APS Deposit Interest Rate. The APS Deposit Interest Rate is the one year Treasury Constant Maturities rate, effective on the first business day of each year as published on the Federal Reserve Website.

BALANCING ACCOUNT

The Company shall establish and maintain a Balancing Account ("Account") for the schedules subject to this provision. Entries shall be made to the Account each month as set forth in the Plan. The Account will include interest applied to over- and under-collected balances based on the effective APS Deposit Interest Rate.

FILINGS

The PCCF and Balancing Account calculations, and workpapers, will be filed with the Commission annually. Workpapers and other documents supporting the calculations that contain proprietary or confidential information will be filed with the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. All of the information is available during the year upon Commission request. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund if those costs are found to be imprudently incurred.

DIRECTLY ASSIGNED POWER SUPPLY COSTS

In cases when power supply costs are incurred for a specific customer or group of customers, the customer or group of customers will be charged the identified costs directly. Power supply costs and related energy sales recovered through direct assignments for both existing and returning customers will be excluded from the computation of the above charges applied to other Standard Offer customers.

Schedule DJR-7RB
Returning Customer Direct Assignment Plan for Administration

Schedule DJR-7RB
Returning Customer Direct Assignment Plan for Administration

General Description

Section 2.6 of the May 17, 1999 Settlement Agreement ("Agreement") in Docket No. E-01345A-98-0473 allows Arizona Public Service Company ("APS") to recover the reasonable and prudent costs associated with compliance and implementation of the Electric Competition Rules beginning July 1, 2004. The Arizona Corporation Commission approved the collection of these costs in Decision No. 66567, Docket No. E-01345A-02-0403. Section 2.6(2) of the Agreement provides the opportunity to recover the costs of providing Standard Offer service to customers who have left a APS Standard Offer service or special contract rate for a competitive generation supplier and are returning to Standard Offer service (for administrative purposes, customers who were Direct Access customers since origination of service and request Standard Offer service would be considered to be returning customers). APS may assign any of the above costs directly to the customer(s) who caused them via a Returning Customer Direct Assignment Charge ("RCDAC"). This will only be done where a customer, or group of customers, with a monthly demand of three MW or greater returns to Standard Offer service and APS did not include their load in planned resource acquisitions. If APS is provided one year's advance notice of the customer's intent to return to Standard Offer service then they are not eligible for a RCDAC. APS may create a special RCDAC in each individual case and require the customer(s) to enter into a service contract that specifies the charge, its duration, and how it will be applied and collected. In situations where an aggregated group of customers wish to return, each customer from the group will be charged the same rate for the same duration and a contract will be required from each customer.

Returning Customer Direct Assignment Charge

The RCDAC will be based on the cost differential between the retail base power supply cost contained in the applicable Standard Offer rate and the cost of the resources required to serve the returning customer(s). The costs associated with serving customers that are required to enter into RCDAC contracts will be kept separate from the retail power supply costs subject to recovery through the Power Supply Adjustment. OATT, Metering, Administration and Power Supply are the types of costs that will be used to develop the RCDAC charge. These costs will be amortized over an appropriate period to allow their timely recovery.

RATE SCHEDULE RCDAC-1
RETURNING CUSTOMER ADJUSTMENT

APPLICATION

The Returning Customers Direct Assignment Charge (" RCDAC") shall apply to customers or groups of customers over 3 MW who left Standard Offer retail service or special contract service for competitive generation suppliers and desire to return to Standard Offer service (or customers who were Direct Access customers since origination of service and request Standard Offer service) and for whom the Company has not planned resource acquisitions. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

RATE

The adjustment will be identified in the Electric Service Agreement between the Customer and APS and will be in addition to the Standard Offer service charges. OATT, Metering, Administrative and Power Supply costs will be used to develop the charge that will be included in the agreement. These costs will be amortized over an appropriate period to ensure their timely recovery.

Schedule DJR-8RB
Competition Rules Compliance Plan for Administration

Schedule DJR-8RB
Competition Rules Compliance Charge Plan for Administration

General Description

Section 2.6 of the May 17, 1999 Settlement Agreement ("Agreement") filed in Docket No. E-01345A-98-0473 allows Arizona Public Service Company ("APS") to recover the reasonable and prudent costs associated with compliance and implementation of the Electric Competition Rules. The Arizona Corporation Commission approved the collection of these costs in Decision No. 66567, Docket No. E-01345A-02-0403.

Competition Rules Compliance Charge

The Competition Rules Compliance ("CRC") costs, including interest, that were incurred from 1999 through the date of implementation of the charge approved in Decision No. 66567 will be amortized over five years. Interest will be calculated using the Federal Reserve Statistical Release, H-15, or its successor non-financial three-month commercial paper rate for each month these costs were accrued. The Competition Rules Compliance Charge ("CRCC") is derived by dividing the CRC costs by the 2005-2009 forecasted energy usage. The charge will be applied to the customer's bills as a monthly kilowatthour charge if it is approved by the Arizona Corporation Commission ("ACC"). It will be terminated at the end of the five year period. A compliance filing will be made within 60 days after the Commission issues an order establishing the CRCC that will become effective.

After the end of the five year period, the CRC account balance will be trued-up to determine the residual over/under collection from the CRCC. The true-up is done by taking the total amortized CRC costs and subtracting the total amount recovered by the CRCC. The difference is the residual over/under collection. The residual amount will be amortized over one month and applied to customers' bills as a monthly kilowatt-hour charge. The charge will be submitted to Commission staff for approval and will be effective for one month and then terminated.

The following is an example of how the CRCC will be calculated:

Example of Competition Rules Compliance Charge Calculation

Line No.			
1	Settlement Period Section 3.3 Over/Under Recovery	$	18,000,000
2	Settlement Period Section 2.6(3) Transition Costs	$	40,500,000
3	Total Settlement Period Transition Costs	$	58,500,000
4	Total Settlement Period Transition Costs	$	58,500,000
5	2005 -2009 Forecased Energy Usage (kWh)		127,000,000,000
6	Settlement Period Transition Cost Charge	$	0.000461

*Numbers shown are for illustration purposes only.

RATE SCHEDULE CRCC-1
COMPETITION RULES COMPLIANCE CHARGE

APPLICATION

The Competition Rules Compliance Charge (" CRCC") shall apply to all retail Standard Offer or Direct Access electric schedules, excluding those which are for solar service. All provisions of the customer's applicable rate schedule will apply in addition to this charge.

RATES

The bill shall be calculated at the following rate:

CRCC

All kWh	$0.000XXX	per kWh

ADDITIONAL REQUIREMENTS

The A.C.C. authorized in Decision XXXXXX that the amortized amount of allowed costs deferred through the date of the implementation of this rate schedule is to be recovered over five years according to the method described in the filed "Competition Rules Compliance Plan for Administration." The CRCC will be canceled once the amortized amount is fully recovered.

Schedule DJR-9RB
System Benefit Adjustment Charge Plan for Administration

Schedule DJR-9RB
System Benefit Adjustment Charge Plan for Administration

General Description

Section 2.6 of the May 17, 1999 Settlement Agreement ("Agreement") filed in Docket No. E-01345A-98-0473 allows Arizona Public Service Company ("APS") to recover the reasonable and prudent costs associated with Arizona Corporation Commission ("Commission") approved system benefit programs not included in rates as of June 30, 1999. The Commission approved the collection of these costs in Decision No. 66567 from Docket No. E-01345A-02-0403. The System Benefit Adjustment Charge ("SBAC") includes Commission approved system benefit programs that are not included in APS' base rates. The types of programs that are eligible for inclusion in the SBAC are low income, demand-side management, consumer education and others that may be approved by the Commission. The SBAC currently includes two separate programs, but additional programs may be added or deleted with Commission approval. The SBAC is applicable to Arizona Public Service Company's ("APS") Retail Electric Rate Schedules (excluding solar service) and is comprised of the Bark Beetle Remediation ("Beetle") Adjustment and the Demand-Side Management ("DSM") Adjustment. On the customer's bill these charges are combined and shown on one line as the SBAC Charge. The SBAC charge is applied to Standard Offer or Direct Access customer's bills as monthly kilowatthour charges that are the same for all customer classes. The charge will be changed effective in billing cycle 1 of the November revenue month and will not be prorated.

Section 1 – Bark Beetle Remediation Adjustment

Description and Allowable Costs

The prolonged drought has weakened the Arizona forest making the trees susceptible to infestation by bark beetles. Approximately 750,000 dead or dying trees caused by the infestation are within falling distance of APS' power lines. APS will have to remove these trees over the next three to five years to protect the system. The allowable costs for the Beetle Adjustment are those associated with tree removal required to protect the Company's transmission and distribution system and also avoid causing forest fires. If the Company receives government or other funding to mitigate the expense of tree removal related to the bark beetle infestation those funds will be credited back to the customers through the SBAC.

Bark Beetle Remediation Charge Calculation

The Bark Beetle Remediation Charge is calculated by dividing the projected 2005 – 2008 program costs by the projected 2005 – 2008 Total Retail Energy (kWh) sales. The result is the SBAC Bark Beetle Remediation Charge that will be applied to the customer's monthly kWh usage. This charge will appear on the bill combined with the DSM

Adjustment Charge as part of the SBAC charge. If APS receives government or other funding to offset the cost of the Bark Beetle Remediation then the Company will calculate a credit based on the projected energy sales over the remaining portion of the original 2005 – 2008 time period. A monthly credit per kWh will be incorporated into the SBAC charge applied to the customer's energy usage.

Example of Bark Beetle Remediation Adjustment Charge Calculation

Line No.			
1	2005 - 2008 Projected Bark Beetle Program Costs	$	33,257,250
2	2005 - 2008 Projected Total Retail Energy Sales (kWh)		114,238,321,000
3	SBAC Bark Beetle Remediation Charge per kWh	$	0.000291

*Numbers shown are for illustration purposes only.

True-Up Procedure

After the Beetle Adjustment is terminated the account balance will be trued-up to determine the residual over/under collection from the adjustment. The true-up is calculated by subtracting the total amount recovered by the Bark Beetle Remediation Charge portion of the SBAC charge from the total actual Beetle Adjustment costs. The difference is the residual over/under collection. The residual amount will be amortized over an appropriate time period and applied to customers' bills as a monthly kilowatt-hour charge that is incorporated into the SBAC charge. The true-up charge, after it is approved by the Commission Staff, will be effective for the approved time period and then terminated.

Filings

APS shall file all of the Bark Beetle Remediation cost and calculation information with the Commission for approval of the charge as part of the 2003 Rate Case. The Company will make an administrative filing with the Commission's Utilities Director for a Bark Beetle Remediation credit should it receive government or other funding for the Bark Beetle Remediation. The credit filing will include a revised tariff sheet with the new SBAC charge. The Bark Beetle SBAC information will also be provided to the Commission staff upon request.

Section 2 – DSM Adjustment

Description

The DSM Adjustment was developed to recover: (1) all capitalized or expensed costs associated with pre-approved DSM programs; (2) lost revenues net of any operational savings due to DSM; and (3) an incentive based on kW savings attributable to customer conservation measures implemented as a result of the DSM programs. The DSM Adjustment will not include capitalized or expensed costs included in base retail rates. The DSM adjustment charge will be recomputed annually.

Allowable Costs

Recovery of all applicable program costs/incentives will be allowed for the programs that have been pre-approved by the Commission Staff. The maximum of annual Program Costs, Net Lost Revenues and Incentives eligible for recovery is $10,000,000. The types of allowable costs are as follows:

Demand Side Management

A. Program Costs	Allowable expenses will include: program development, implementation, promotion, administrative and general, monitoring/metering costs, advertising, educational expenditures, incentives, research and development, data collection (such as end-use), tracking systems, demonstration facilities and all other activities required to design and implement cost effective DSM for DSM Programs that are pre-approved and are not in base rates. For those DSM programs that generate revenue, the revenue will be credited back to the DSM Adjustment.
B. Net Lost Revenues	Represents total estimated annual lost revenues between rate cases, resulting from reduced sales as a consequence of conservation measures implemented as a part of the DSM Adjustment, net of any system savings (fuel costs, variable O&M, etc.) realized because of reduced sales.
C. Incentives	A financial Incentive on kW savings to be retained by the Company for participating in a program. The estimate of the Incentive to be retained by the Company is based on a return approximately equivalent to the return on the alternative supply side resources avoided through DSM. For DSM measures installed in a given year, a stream of incentive payments shall be established for the life of the DSM measure.

Pre-Approval Process for New Programs

APS will submit a written request for DSM program approval to the Commission Staff as provided for in Decision No. 59601 dated April 24, 1996. The request will contain a description of the program, expected level of participation, expected kW and kWh savings, description of the implementation/marketing plan, monitoring and evaluation plan and estimates of annual Program Costs, Net Lost Revenues and Incentives.

Estimates of approved/proposed Costs, Net Lost Revenues, and Incentives are included in Schedule 1. Schedule 1 will be updated each year and used in calculating the applicable charge for the ensuing period. The formula used for determining the estimated Incentive for a particular program is shown below.

The Company will include with each program presented to Staff a monitoring plan that reasonably balances monitoring costs and accuracy. The monitoring plan will describe how an estimate of kW and kWh savings is to be determined and how process effectiveness will be determined. The Company will use the monitoring information to revise or terminate an energy efficiency program as described below.

Determination of True-up Amount

The actual costs (Schedule 2) resulting from participation in programs under the DSM Adjustment will be compared to the actual revenues (Schedule 3) received by the Company through imposition of the DSM Adjustment charge on customer bills. The Reconciliation Schedule for the Balancing Account (Schedule 4) and its supporting schedules will be filed annual as part of the Company's reporting requirements in conjunction with Staff's annual review of the DSM Adjustment. These schedules will include any adjustments made by Staff during the course of the year. Any amounts remaining in the balancing account due to over/under recovery will be used in calculating the DSM Adjustment charge for the next period.

Revisions or Termination of Programs

Staff will be notified in writing of revisions or terminations of a program. If for any reason an approved program is terminated the Company will be entitled to recover all Program Costs and any Net Lost Revenues and Incentives associated with kW and kWh savings. A program could be terminated because it was successful and no further incentives for customers are needed to encourage use/participation in the conservation measure. A program may also be terminated if it was unsuccessful despite good planning.

Determination of DSM Adjustment Charge

The annual DSM Adjustment Charge ("Charge") will be calculated based on the estimated aggregate costs of pre-approved programs and programs pending approval for the Charge period. Any over/under recovery of revenues resulting from specific program additions or deletions or findings from program monitoring will be accumulated in the Balancing Account for resolution during the subsequent annual Staff review of the DSM Adjustment.

The Charge is calculated as follows:

$$\text{DSM Adjustment Charge} = \frac{(PC + NLR + I) \pm TUB}{\text{Energy Sales}} \leq CAP$$

Where:	PC	=	DSM related Program Costs, as described above, projected for the next Charge Period.
	NLR	=	Net Lost Revenues, as described above, projected for the next Charge Period.
	I	=	Incentives, as described above, projected for the next Charge Period.
	TUB	=	Any balance in the "true-up" account that has accumulated in the previous year. The true-up procedure is described above.
	Energy Sales	=	Projected energy sales under the applicable electric rate schedules during the Charge Period when this Charge will be in effect.
	CAP	=	Maximum amount allowed for DSM Adjustment expenditures.
	Charge Period	=	The 12 month period beginning with the first billing cycle during XXXXXXX of the current year and ending with the last billing cycle of XXXXXX of the next year.

An example of the Charge calculation is on Schedule 5. The Company's estimate of the applicable Charge for the subsequent Charge Period will be submitted for Staff approval each year.

Unless otherwise acted upon by the Commission Staff, changes in the DSM Adjustment portion of the SBAC charge will go into effect in billing cycle 1 of the November revenue month.

Calculation of Incentive

The Incentive reward will be calculated as follows:

Reward = Investment x Value

Where:	Reward	=	APS' allowed annual Incentive in \$/kW – Year
	Investment	=	Percent return on deferred capacity costs, reflecting the reduced risk on the forgone return on investment in deferred future capacity, or purchased power, attributable to the DSM Adjustment mechanism.
	Value	=	Remaining balance of the present value of deferred capacity attributable to the DSM/Conservation measures in \$/kW.

Progress Reports and Annual Reporting

The Company will file semi-annual DSM progress reports with Staff that summarize by program: actual Program Costs; Net Lost Revenues; Incentives; the status (planned, on-going, terminated); level of participation; monitoring activities and results; kW and kWh savings; and the current Balancing Account level. The reports are due to the Staff within 60 days of the end of the reporting period.

The Company will file annually a report containing information on projected Program Costs, Net Lost Revenues, and Incentive amounts for the upcoming Charge period (see Schedule 1). Schedule 1 provides projected budget information for all pre-approved programs and programs pending approval.

APS will also annually file the calculation and schedules supporting the upcoming Charge (Schedule 5) and the Reconciliation Schedule for the Balancing Account (Schedule 4). The Balancing Account shows the amount of any over/under revenue recovery, net of any adjustments.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Example DSM Adjustment
ESTIMATED Annual Program Costs, Net Lost Revenues and Incentive Amounts
Charge Period XXXXXXX 1, YYYY through XXXXXXX 31, YYYY

	Program Name	Program Costs	Net Lost Revenues	Incentive Amounts	Total
Program 1	Sample DSM program 1	$2,900,000	$75,000	$25,000	$3,000,000
Program 2	N/A	$0	$0	$0	$0
	Total	$2,900,000	$75,000	$25,000	$3,000,000

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
Example DSM Adjustment
ACTUAL Monthly Program Costs, Net Lost Revenues and Incentive Amounts
Charge Period XXXXXX 1, XXXX through XXXXXXX 31, XXXX

	Program Name	Nov XX	Dec XX	Jan XX	Feb XX	Mar XX	Apr XX	May XX	Jun XX	Jul XX	Aug XX	Sep XX	Oct XX	Total
Program 1	Sample DSM program 1													
	Program Costs	$ 241,000	$ 241,000	$ 241,000	$ 241,000	$ 241,000	$ 241,000	$ 241,000	$ 241,000	$ 241,000	$ 241,000	$ 241,000	$ 241,000	$ 2,892,000
	Net Lost Revenues	$ 6,250	$ 6,250	$ 6,250	$ 6,250	$ 6,250	$ 6,250	$ 6,250	$ 6,250	$ 6,250	$ 6,250	$ 6,250	$ 6,250	$ 75,000
	Incentive Amounts	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 2,083	$ 25,000
	Total	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 2,992,000
Program 2	N/A													
	Program Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Net Lost Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Incentive Amounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
All Programs	Total	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 249,333	$ 2,992,000

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3
Example DSM Adjustment
ACTUAL DSM Adjustment Charge Revenues
Charge Period XXXXXXX 1, XXXX through XXXXXXX 31, XXXX

Line No.	Mth	Actual Retail Energy Sales		Effective DSM Adj. Charge $ per kWh		Actual Revenue From DSM Adj. Charge
1	Nov XX	1,479,514,000	$	0.000110	$	162,747
2	Dec XX	1,670,065,000	$	0.000110	$	183,707
3	Jan XX	1,623,890,000	$	0.000110	$	178,628
4	Feb XX	1,424,307,000	$	0.000110	$	156,674
5	Mar XX	1,564,672,000	$	0.000110	$	172,114
6	Apr XX	1,550,540,000	$	0.000110	$	170,559
7	May XX	2,008,611,000	$	0.000110	$	220,947
8	Jun XX	2,189,461,000	$	0.000110	$	240,841
9	Jul XX	2,495,718,000	$	0.000110	$	274,529
10	Aug XX	2,480,030,000	$	0.000110	$	272,803
11	Sep XX	2,204,127,000	$	0.000110	$	242,454
12	Oct XX	1,662,336,000	$	0.000110	$	182,857
		$ 22,353,271,000			$	2,458,860

Computed PCCF to move forward to Schedule 4, Line 2 $ 2,458,860

ARIZONA PUBLIC SERVICE COMPANY
Schedule 4
Example Calculation of the DSM Adjustment Charge
Charge Period XXXXXXX 1, XXXX through XXXXXXX 31, XXXX

Line No.		
1	Beginning Balance as of Oct. 31, XXXX	$0
2	Charge Revenues Collected During Period (From Schedule 3)	$2,458,860
3	Actual Program Costs, Net Lost Revenues & Incentive Amounts (From Sch. 2)	$2,992,000
4	Over/(Under) Recovery Balance (Line 2 - Line 3)	($533,140)
5	Ending Balance (Line 1 + Line 4)	($533,140)

ARIZONA PUBLIC SERVICE COMPANY
Schedule 5
Example Calculation of the DSM Adjustment Charge
Charge Period XXXXXXX 1, YYYY through XXXXXXX 31, YYYY

Line No.			
1	Projected Program Costs	$2,900,000	
2	Projected Net Lost Revenues	$75,000	
3	Projected Incentives	$25,000	
4	True-Up Balance (From Sch. 4 Ending Balance, Reversed Sign)	$533,140	
5	Total Costs	$3,533,140	
6	Maximum Allowable Recovery	$10,000,000	
7	Total Recoverable Costs (Lesser of Line 5 or Line 6)		$3,533,140
8	Total Recoverable Costs from Line 7	$3,533,140	
9	Projected Sales for Next Charge Period	24,000,000,000	
10	DSM Adjustment Charge		$ 0.00015

RATE SCHEDULE SBAC-1
SYSTEM BENEFIT ADJUSTMENT CHARGE

APPLICATION

The System Benefit Adjustment Charge ("SBAC") shall be applied monthly to every metered and/or non-metered retail Standard Offer or Direct Access electric service with the exception of solar service. All provisions of the customer's currently applicable rate schedule will apply in addition to this surcharge. The SBAC includes Arizona Corporation Commission ("Commission") approved system benefit programs that are not included in APS' base rates. The SBAC currently includes two programs but additional programs may be added or deleted with Commission approval. The two programs that currently comprise the SBAC are the Bark Beetle Remediation ("Beetle") Adjustment and the Demand-Side Management ("DSM") Adjustment. On a customer's bill these charges are combined and shown as the SBAC charge. The SBAC charge is applied to Standard Offer or Direct Access customer's bills as monthly kilowatthour charges that is the same for all customer classes. The SBAC charge will be changed in billing cycle 1 of the November revenue month and will not be prorated.

RATE

The charge shall be calculated at the following rate:

SBAC Charge

All kWh	$0.000XXX	per kWh

BARK BEETLE REMEDIATION ADJUSTMENT

This charge collects the allowable costs associated with the removal of trees that have been weakened by the bark beetle infestation. These trees have to be removed over the next three to five years to protect the system. If the Company receives government, or other, funding to offset the cost of the Bark Beetle Remediation then the Company will calculate a monthly credit per kWh that will be incorporated into the SBAC charge applied to the customer's bill. After the Bark Beetle Adjustment is terminated, the account balance will be trued-up to determine the residual over/under collection from the adjustment as described in the SBAC Plan for Administration.

DSM ADJUSTMENT

The DSM Adjustment was developed to recover: (1) all capitalized or expensed costs associated with pre-approved DSM programs; (2) lost revenues net of any operational savings due to DSM; and (3) an incentive based on kW savings attributable to customer conservation measures implemented as a result of the DSM programs. The DSM Adjustment charge portion of the SBAC charge is recomputed annually. This adjustment includes only Commission pre-approved DSM projects. Unless otherwise acted upon by the Commission Staff, changes in the DSM Adjustment portion of the SBAC Charge will go into effect in billing cycle 1 of the Novemver revenue month. It will not be prorated.

BARK BEETLE REMEDIATION ADJUSTMENT FILINGS

The Company will make an administrative filing with the Commission's Utilities Director for a Bark Beetle Remediation credit should it receive government funding for the Bark Beetle Remediation. The credit filing will include a revised tariff sheet with the new SBAC charge. The Bark Beetle SBAC information will also be provided to the Commission staff upon request.

DSM ADJUSTMENT FILINGS

The Company will file semi-annual DSM progress reports with Staff that summarize by program: actual Program Costs; Net Lost Revenues; Incentives; the status (planned, on-going, terminated); level of participation; monitoring activities and results; kW and kWh savings; and the current Balancing Account level. The reports are due to the Staff within 60 days of the end of the reporting period.

The Company will annually file a report containing information on projected Program Costs, Net Lost Revenues, and Incentive amounts for the upcoming Charge period. APS will also file annually the calculation of the upcoming charge and the Reconciliation Schedule for the Balancing Account. The Balancing Account shows the amount of any over/under revenue recovery, net of any adjustments.

Schedule DJR-10RB
Transmission Cost Adjustment Clause Plan for Administration

Schedule DJR-10RB
Transmission Cost Adjustment Clause Plan for Administration

General Description

The Transmission Cost Adjustment ("TCA") clause is applicable to Arizona Public Service Company's ("APS") Retail Electric Rate Schedules, with the exception of solar service, and is calculated annually. It is applied to the Standard Offer customer's bill as a monthly kilowatthour charge and it will be the same for all customer classes. The charge will take effect in billing cycle 1 of the April revenue month and it will not be prorated.

Allowable Costs

Included in the TCA are the Transmission and Ancillary Services costs incurred by APS to provide service to its Standard Offer customers.

Calculation

The Transmission Cost Component Factor ("TCCF") is calculated by dividing the calendar year's Annual Transmission and Ancillary Service costs by the calendar year's Annual Retail kWh sales. The result is the Annual Average Transmission and Ancillary Service Cost per kWh. The Base System Average Transmission and Ancillary Service Cost per kWh is then subtracted from the Annual Average Transmission and Ancillary Service Cost per kWh. This produces the Applicable TCCF. The Applicable TCCF can be either positive or negative.

Balancing Account

APS will establish a Balancing Account that accumulates the dollars associated with the under-collection or over-collection from the application of the TCA. The account will accrue interest. The Balancing Account will be updated monthly. Entries will be made as follows:

1. A debit or credit entry equal to the difference between the amount recovered from both Base System Average Transmission and Ancillary Service Cost per kWh plus the Applicable TCCF and the Transmission and Ancillary Service Costs.

2. A debit or credit entry for interest will be applied to the account balance based on the effective APS Deposit Interest Rate that the Company applies to customer deposits. The APS Deposit Interest Rate is the one year Treasury Constant Maturities rate, effective on the first business day of each year as published on the Federal Reserve Website.

3. A debit or credit entry equal to the kilowatthours billed for the month under the rate schedules subject to the TCA charge multiplied by the effective Amortization Charge (as described below). If an Amortization Charge is not in effect then no entry will be made.

4. A debit or credit entry for refunds or payments authorized by the Arizona Corporation Commission ("ACC or Commission").

Amortization Charge

The Company can file a request with the Commission Staff for approval of an Amortization Charge if the Account balance exceeds plus or minus $10,000,000. The Commission, after reviewing the application, may authorize the balance to be amortized and the time period of its recovery. If the Company files an Amortization Charge request the charge will be calculated by taking the Balancing Account's End of Month Balance and dividing it by the Company's estimate of the Total Retail Energy Sales for the filed amortization time period. This calculation yields a monthly kilowatthour charge that, if approved, is added to the customer's bills over the approved time period. These calculations will be filed with the Commission along with the request to implement the charge.

Filings

The Company shall annually file with the Commission a request for approval of a new TCCF and the calculations supporting the TCCF and the Balancing Account. This filing will include a revised tariff sheet with the new TCCF charge.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1
Example TCCF Calculation Methodology

Line No.	Mth	(a) Calendar Year's Transmission & Ancillary Service Costs	(b) Calendar Year's Retail Energy Sales kWh	(c) Trans. & Anc. Service Cost $ per kWh	(d) Base System Trans. & Anc. Serv. Cost $ per kWh	(e) TCCF $ per kWh
				(a/b)		(c-d)
1	Jan	$ 9,139,148	1,963,130,000			
2	Feb	$ 8,885,964	1,801,819,000			
3	Mar	$ 7,987,381	1,712,984,000			
4	Apr	$ 7,977,732	1,665,949,000			
5	May	$ 8,551,184	1,844,862,000			
6	Jun	$ 10,401,155	2,216,556,000			
7	Jul	$ 12,309,966	2,615,184,000			
8	Aug	$ 12,553,591	2,699,139,000			
9	Sep	$ 12,181,966	2,575,503,000			
10	Oct	$ 10,353,510	2,154,054,000			
11	Nov	$ 8,369,791	1,768,036,000			
12	Dec	$ 8,460,552	1,834,804,000			
13		$ 117,171,942	24,852,020,000	$ 0.004715	$ 0.004760	$ (0.000050)

Applicable TCCF $ (0.000050)

ARIZONA PUBLIC SERVICE COMPANY
Schedule 2
Example TCA Balancing Account Calculations
December, XXXX

Line No.			
1	Beginning Balance	$ 2,538,368	
2	Transmission and Ancillary Service Costs	$ 8,460,552	
3	Total Costs to be Recovered (Line 1 + Line 2)		$ 10,998,920
4	Retail Energy Sales - (kWh)	1,834,804,000	
5	Base System Trans. & Anc. Service Cost per kWh	$ 0.0047600	
6	Amt. Recovered by Base Sys. Trans. & Anc. Service Cost per kWh (Line 4 x Line 5)		$ 8,733,667
7	Retail Energy Sales - (kWh)	1,834,804,000	
8	Applicable TCCF - per kWh	$ (0.000050)	
9	Amount recovered from Applicable TCCF Rate (Line 7 x Line 8)		$ (91,740)
10	Total Amount Recovered (Line 6 + Line 9)		$ 8,641,927
11	Adjustments (if applicable)		$ -
12	Balance before Interest (Line 3 - Line 10, + or - Line 11)		$ 2,356,993
13	Monthly Interest (Line 1 *(1.31%/12))		$ 2,771
14	Balance after Interest (Line 12 + Line 13)		$ 2,359,764
17	Balance from Line 14	$ 2,359,764	
18	Total Amount of Balance to be Amortized (if any)	$ -	
19	Ending Balance (Line 17 - Line 18)		$ 2,359,764
20	Total Amount of Balance to be Amortized from Line 18	$ -	
21	Estimated Retail Energy Sales for Amortization Period (kWh)	25,846,100,800	
22	Balancing Account Amortization Charge (Line 20 / Line 21)		$ -

RATE SCHEDULE TCA-1
TRANSMISSION COST ADJUSTMENT

APPLICATION

The Transmission Cost Component Factor ("TCCF") and Amortization Charge shall apply to all Standard Offer retail electric schedules, excluding those which are for solar service. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

TCCF ANNUAL ADJUSTMENT

Standard Offer rate schedules covered by this charge include an Average Transmission and Ancillary Service Cost ("ATASC") of $0.00476 per kilowatt-hour. In accordance with A.C.C. Decision No. XXXXX, an annual adjustment to the ATASC will be made through a change in the TCCF that is based upon the prior year's annual Transmission and Ancillary Service costs and retail energy sales. The calculation method is set forth in the filed Transmission Cost Adjustment Plan for Administration (the "Plan"). This Adjustment will be applied to kilowatthour sales under applicable electric schedules.

BALANCING ACCOUNT

The Company shall establish and maintain a Balancing Account ("Account") for the schedules subject to this provision. Entries shall be made to the Account each month as set forth in the Plan. The Account will include interest applied to over- and under-collected balances based on the effective APS Deposit Interest Rate. The APS Deposit Interest Rate is the one year Treasury Constant Maturities rate, effective on the first business day of each year as published on the Federal Reserve Website. If the Account's balance exceeds plus or minus $10,000,000 the Company can file a request with the Arizona Corporation Commission ("Commission") to convert the existing balance into a kilowatthour charge based on appropriate amortization period. The result is the Amortization Charge. The Amortization Charge will be charged to the applicable rate schedules until the amortization period is over.

RATES

The charge shall be calculated at the following rate:

TCCF

All kWh	$0.000XXX	per kWh

Amortization Charge

All kWh	$0.000XXX	per kWh

FILINGS

The Company shall file Transmission Cost Adjustment information annually with the Commission Staff. These filings will include all of the calculations regarding the TCCF and the Balancing Account and the request for approval of a new TCCF.

Schedule DJR-11RB
Environmental Portfolio Standard Surcharge Plan for Administration

Schedule DJR-11RB
Environmental Portfolio Standard Surcharge Plan for Administration

General Description

The Environmental Portfolio Standard Surcharge ("EPS Surcharge") is applicable to Arizona Public Service Company's ("APS") Retail Electric Rate Schedules and is set forth in A.A.C. R-14-2-1618 and amended by Arizona Corporation Commission Decision No. 63364 (February 8, 2001). The EPS Surcharge is applied to both Standard Offer and Direct Access customer bills as a monthly kilowatt-hour charge and will be the same for all customer classes. This charge will be calculated annually and applied to customer bills as of the first billing cycle of the April revenue month.

Cost Recovery and Disposition of Funds

Funds collected as a result of the EPS Surcharge will be separately held for current and future use specifically to implement the solar resource and/or environmentally friendly renewable electricity technology requirements for Load Serving Entities as set forth in A.A.C. R14-2-1618, or as subsequently amended by an order of the Commission. Recovery of all applicable program costs required to meet the Environmental Portfolio Standard as defined in A.A.C. R14-2-1618 or as subsequently amended will be allowed up to a ceiling amount of $93,000,000 annually less the Environmental Portfolio Standard funds collected through base rates or through other EPS Surcharge mechanisms. Currently, the amount of EPS funding collected through base rates is approximately $6,000,000 which leaves $87,000,000 to be collected from the EPS Surcharge. From time to time, but not more than annually, APS will evaluate program spending requirements, and the EPS Surcharge will be recomputed and submitted for Commission Staff approval. A balancing account will be used to carry forward any over or under recovery of EPS Surcharge funds to the following year.

Calculation

The EPS Surcharge is calculated by dividing the annual required recovery by the projected total retail kilowatt-hour sales for the following calendar year. The resulting EPS Surcharge will be applied as a line item to the customer's bill. The following is an example of the calculation:

Example of Environmental Portfolio Standard Surcharge Calculation

Line No.			
1	Annual Environmental Portfolio Standard Recovery	$	87,000,000
2	Balancing Account Over/(Under) Recovery	$	-
3	Total Recovery Amount	$	87,000,000
4	Projected Calendar Year Total Retail kWh Sales		23,500,000,000
5	EPS Surcharge per kWh (Line 3 / Line 4)	$	0.003702

*Numbers shown are for illustrative purposes only.

<u>Reporting Requirements</u>

Annual reports will be filed with Commission Staff within 60 days after the end of each calendar year. These reports will contain the dollar amount of EPS funds collected during the previous calendar year, the amount of funds expensed during that year, and a description of all solar or other renewable projects for which the funds were spent.

RATE SCHEDULE EPS-2
ENVIRONMENTAL PORTFOLIO STANDARD SURCHARGE

AVAILABILITY

The Environmental Portfolio Standard Surcharge ("EPS Surcharge"), as mandated by the Arizona Corporation Commission, applies to all customers in all territory served by the Company.

APPLICATION

The EPS Surcharge shall be applied monthly to every metered and/or non metered retail Standard Offer or Direct Access electric service, excluding those services which are for a solar service. All provisions of the customer's applicable rate schedule will apply in addition to this surcharge.

RATE

The EPS Surcharge shall be applied to customer bills at the following rate:

All classes	$0.00XXXX	per kWh

TERMS AND CONDITIONS

Service under this rate schedule is subject to the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services and the Company's Schedule 10, Terms and Conditions for Direct Access. These schedules have provisions that may affect the customer's bill. In addition, service may be subject to special terms and conditions as provided for in a customer contract or service agreement.

APS-10R

EXHIBIT

APS-10R
admitted

REBUTTAL TESTIMONY OF

LAURA L. ROCKENBERGER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

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REBUTTAL TESTIMONY OF LAURA L. ROCKENBERGER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. <u>INTRODUCTION.</u>

Q. PLEASE STATE YOUR NAME.

A. Laura L. Rockenberger.

Q. ARE YOU THE SAME LAURA ROCKENBERGER THAT SUBMITTED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. In my rebuttal testimony, I address the depreciation issues in Staff witness Michael Majoros's direct testimony, including the general impact on APS and its customers of his recommendations. In so doing, I identify certain specific errors that he made and respond to his assertion that APS is incorrectly implementing Statement of Financial Accounting Standards ("SFAS") No. 143 and FERC Order 631. I also explain how Mr. Majoros's recommendations fail to meet the requirements of the Commission's own rules for depreciation and respond to his flawed conclusion that an accounting order for APS' SFAS No. 143 implementation is inappropriate.

In addition to these depreciation issues, I also respond to Staff witness Steven Carver and RUCO witness William A. Rigsby regarding the Cash Working Capital requirements of APS and the lead-lag study that was performed to determine Cash Working Capital. In addition, I respond to the direct testimony of Marylee Diaz Cortez of RUCO who proposes decreasing part of APS' rate base reflecting the Independent Spent Fuel Storage Installation ("ISFSI") associated with Palo Verde. Finally, I sponsor Reconstruction Cost New Less Depreciation ("RCND") calculations given the pro forma adjustments proposed by the Company in rebuttal testimony.

Q. IS THE COMPANY PRESENTING OTHER REBUTTAL WITNESSES ON DEPRECIATION ISSUES?

A. Yes. In addition to my rebuttal testimony, Dr. Ronald E. White of Foster Associates will explain why Mr. Majoros's claims regarding net salvage and the implications of SFAS No. 143 and FERC Order 631 are both incorrect and vastly overstated, and would represent a significant and unwarranted departure from accepted depreciation practices in Arizona. Also, the rebuttal testimony of Mr. John Wiedmayer of Gannett Fleming, who conducted APS' most recent depreciation study, will respond to Mr. Majoros's proposed depreciation lives for the Company's transmission, distribution and general plant assets and for the Pinnacle West Energy Corporation ("PWEC") generation assets.

II. <u>SUMMARY OF TESTIMONY</u>.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Staff witness Majoros is the only witness to take issue with APS' proposed depreciation rates. Depreciation expense is an important source of internal generation of funds, and is needed to help APS fund the significant capital expenditures anticipated over the next few years. It is also how investors recover their investment in the Company's rate base. Mr. Majoros's recommendation would dramatically reduce the Company's current depreciation expense. He creates his reduction in the Company's revenue requirement by (1) not collecting enough removal costs from customers who benefit from assets used by the Company in providing service, (2) unreasonably extending the depreciable lives of the Company's transmission, distribution and general plant, and (3) unreasonably extending the lives of the PWEC units. Ignoring all authority to the contrary and the actions of other state utility commissions, Mr. Majoros asserts that his analysis is required by SFAS No. 143, a recent accounting pronouncement addressing financial reporting requirements for removal costs. In fact, Mr. Majoros is simply using this pronouncement to inflict a radical approach to removal costs and net salvage that he has been advocating for over twenty years.

His recommendations are flawed and ignore both the Commission's own rules and the long-established practices for depreciation of utility plant in Arizona. Removal costs, one of the most significant components in determining net salvage for utility assets, should be paid in a pro rata manner over the service life of an asset by the customers that benefit from that asset. This well-accepted principle is the foundation for Rule R14-2-102(B)(3), which requires net salvage to be distributed in a rational and systematic manner over the estimated service life of an asset. Mr. Majoros recommends an overhaul of the calculation of net salvage by proposing that APS use only a five-year historical average of removal or salvage expense. This unreasonable approach, which forces removal costs on future customers potentially years after an asset is retired, is certainly outside the norm for utility commissions in the United States and the Company's attorneys believe it could not be adopted in Arizona without a rulemaking proceeding. This normalized net salvage proposal is refuted in more detail in Dr. White's rebuttal testimony.

Contrary to Mr. Majoros's suggestion that the depreciation practices of APS—and apparently many other utilities across the country—violate SFAS No. 143 and FERC Order 631, the Company's accounting is sound, audited, and fully complies with both pronouncements. The accounting order that APS has requested to make its implementation of SFAS No. 143 revenue neutral and to comply with Rule 102 is appropriate. As the Oregon Public Utility Commission Staff recently concluded when recommending a similar accounting order for Pacific Power & Light, "SFAS 143 should not be used for ratemaking." SFAS No. 143 is primarily focused on financial statement presentation, rather than on cost recovery which is the proper focus of ratemaking. In fact, the use of SFAS No. 143 as Mr. Majoros recommends results in both "back-end loading" removal costs and inflates such costs for third party expenses that may never be incurred by the utility, if the utility performs the removal work. Fortunately, SFAS No. 71, which addresses accounting for regulation, can be used to recognize differences between the Company's financial reporting and the Commission's ratemaking decisions and make implementation of SFAS No. 143 revenue neutral.

Finally, to yet further depress the Company's depreciation expense, Mr. Majoros also has recommended longer and unreasonable lives for certain key transmission, distribution and general plant accounts. His recommendations significantly extend both the current Commission-approved lives and APS' proposed lives for these accounts from the Company's depreciation study. Mr. Majoros reaches this unreasonable result by employing a mechanical approach to service life analysis that rejects the use of any engineering and professional judgment and fails to conform to acceptable statistical methods. Also, APS already has some of the most conservative electric utility depreciation rates in the Western United States and Arizona for transmission and distribution plant. For Mr. Majoros to propose further reductions in these rates without so much as considering the depreciation rates of comparable utilities further underscores the unreasonable nature of his recommendations. These issues, as well as his failure to appropriately evaluate the lives of the PWEC generation assets, are explained in Mr. Wiedmayer's rebuttal testimony.

III. DEPRECIATION AND SFAS 143

Q. HAVE YOU REVIEWED STAFF'S TESTIMONY AND EXHIBITS RELATING TO DEPRECIATION?

A. Yes. Mr. Majoros's testimony provides his analysis of the depreciation studies filed for APS and for the PWEC generation assets that APS is requesting be included in the Company's rate base. He also discusses what he believes are the impacts of a new accounting standard, SFAS No. 143, which addresses Asset Retirement Obligations ("AROs") and accounting for certain removal costs.

Q. WHAT RECOMMENDATIONS DID MR. MAJOROS MAKE IN HIS TESTIMONY?

A. Mr. Majoros has recommended a dramatic change in ratemaking policy that results in a 15.6 percent reduction of the overall annual depreciation accrual for APS. In dollar terms, that is a reduction of $44.3 million per year. This reduction is based on his proposals to (1) reduce the accrual for removal costs (what he calls the "negative net salvage rates") to zero, which results in an annual reduction of $31.6 million, and (2) increase the depreciable lives and thus reduce the depreciation rates on the Company's transmission, distribution and general plant assets, which reduces the annual depreciation accrual by $12.7 million. Mr. Majoros has also recommended that the annual depreciation accrual for the PWEC assets be reduced by $13.7 million to $27.8 million based on his review of the depreciation rates included in the depreciation study. Finally, Mr. Majoros incorrectly asserts that APS is violating Generally Accepted Accounting Principles ("GAAP") and FERC Order 631 by continuing to accrue for removal costs that are not subject to the new SFAS No. 143 accounting standard.

Q. DO YOU AGREE WITH MR. MAJOROS'S RECOMMENDATIONS?

A. No. I strongly disagree with each of his positions, as do Dr. White and Mr. Wiedmayer. Mr. Majoros's proposal violates the Commission's own rules for depreciation by proposing only a current period recognition of removal costs. Additionally, for AROs addressed in SFAS No. 143, Mr. Majoros's recommendation could result in excess removal costs being collected over the life of an asset and returned to customers only after the actual removal is completed. In both cases, the result is that costs are not distributed in a rational manner over the life of an asset.

I also believe that Mr. Majoros's recommendations are unreasonable because APS' depreciation rates are already among the lowest and most conservative of any utility in the Western United States. The following table shows the composite depreciation rates for categories of plant accounts for which Mr. Majoros is recommending changes from APS' existing and proposed depreciation rates:

COMPARISION OF DEPRECIATION RATES ON TRANSMISSION, DISTRIBUTION AND GENERAL PLANT BY VARIOUS UTILITY COMPANIES IN SOUTHWEST UNITED STATES

Company	Transmission	Distribution	General
APS Existing Rates	**2.26%**	**3.41%**	**4.93%**
SRP (1)	2.20%	4.61%	6.46%
Tucson Electric Power(1)	3.34%	3.40%	8.88%
UNS Electric(1)	3.61%	4.48%	5.34%
Nevada Power(2)	2.48%	2.71%	6.61%
Public Service of New Mexico(2)	2.59%	3.36%	4.96%
SCE (2)	2.25%	3.92%	9.38%
SDGE (2)	2.73%	4.61%	5.80%
PG&E (2)	3.24%	2.86%	11.20%
Average Rates	**3.09%**	**4.17%**	**7.95%**
APS Proposed Rates	**2.24%**	**2.80%**	**6.18%**
Majoros Proposed rates(3)	**2.02%**	**2.43%**	**4.59%**
Majoros Proposed rates(4)	**1.59%**	**2.25%**	**4.44%**

(1) Rates provided by company
(2) Information from FERC Form 1 data
(3) Without Normalized Net Salvage Proposal
(4) With Normalized Net Salvage Proposal

Dr. White and Mr. Wiedmayer discuss in more detail the specific flaws in Mr. Majoros's depreciation analysis, but this benchmarking demonstrates how unreasonable Mr. Majoros's recommendations are for APS.

Q. HOW IS MR. MAJOROS'S RECOMMENDATION TO REDUCE THE DEPRECIATION ACCRUAL FOR REMOVAL COSTS TO ZERO INCONSISTENT WITH THE COMMISSION'S RULES?

A. Rule R14-2-102(B)(3) provides that

> The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and [systematic] manner over the estimated service life of such plant.

(Emphasis added.) That is how APS and to my knowledge all other regulated utilities in Arizona have been accounting for depreciation for decades with the approval of both Staff and the Commission. This rule ensures that customers are fairly treated as they enter and leave APS' system, so that all customers who benefit from the current use of an asset also pay a pro rata share of the removal costs (the net salvage) for that asset. Without so much as mentioning that rule, Mr. Majoros recommends using a five-year average of removal costs that will not provide for the recovery of removal costs over the life of the asset in a systematic or rational manner.

Q. WHY DON'T MR. MAJOROS'S RECOMMENDATIONS PROVIDE FOR THE RECOVERY OF REMOVAL COSTS OVER THE LIFE OF THE ASSET IN A SYSTEMATIC OR RATIONAL MANNER?

A. Mr. Majoros essentially proposes a current period recognition of removal costs, requiring future customers to pay for removal costs for assets in service today. For example, if APS removes assets 20 years from now, and incurs removal costs that are higher than the five-year average allowance proposed by Mr. Majoros, customers in the future will be required to pay costs that were incurred to serve customers today. His recommendations are both irrational from a rate making perspective and would result in precisely the inequities that Rule 102 seeks to avoid.

Q. IF APS HAS BEEN COLLECTING HIGHER REMOVAL COSTS IN RATES THAN IT HAS BEEN SPENDING, WHY ISN'T THE "AVERAGE REMOVAL COST" APPROACH RECOMMENDED BY MR. MAJOROS REASONABLE?

A. The Commission's rules and practices in Arizona reflect generally a "straight-line remaining-life" method of depreciation. This approach requires that front-end capital costs (construction and acquisition costs) and back-end capital costs (future removal costs) be paid for by users of the assets in equal amounts over the service life of the asset. Such costs are collected and deducted from rate base regardless of the current level of retirements. For example, if in 2002 APS did not install or retire a single power plant (thus incurring no removal costs) it is still necessary to collect depreciation including net salvage from the users of the Company's power plants. Regulated utilities like APS cannot simply ignore the intergenerational inequities that would result from postponing recovery of such costs and collecting them from future customers who did not benefit from the assets.

Q. DO MR. MAJOROS'S RECOMMENDATIONS ON THE LIVES FOR APS' TRANSMISSION, DISTRIBUTION AND GENERAL PLANT HAVE AN EFFECT ON HIS RECOMMENDATION TO LIMIT THE RECOVERY OF NET SALVAGE?

A. Yes, it significantly compounds the problem to the detriment of APS and future customers. When asset lives are lengthened, as Mr. Majoros proposes for APS' transmission, distribution and general plant accounts, reuse salvage values decline (because the assets are older at retirement) and the cost of removal increases due to additional inflation of labor and non-labor costs. This results in a higher negative net salvage rate as a percentage of the original cost of the asset. As a result, lengthening the lives of these assets decreases depreciation expense, but increases the negative net salvage associated with the asset. Mr. Majoros's recommendation would punish APS twice—once by unreasonably reducing the depreciation rate and then again by wholly ignoring the increase in negative net salvage associated with these assets.

Q. DOES SFAS NO. 143 CHANGE THE TREATMENT OF REMOVAL COSTS FOR RATEMAKING PURPOSES?

A. No. It changes how removal costs are treated only for financial statement purposes and only for certain types of assets. The Financial Accounting Standards Board ("FASB") issued SFAS No. 143, "Accounting for Asset Retirement Obligations," in June 2001 and that standard was effective for APS as of January 1, 2003, after the close of the test year. SFAS No. 143 establishes accounting requirements for the recognition and measurement of certain liabilities associated with the retirement of tangible long-lived assets. The Statement defines Asset Retirement Obligations ("AROs") as retirement obligations where the removal requirement results from law, contract or promissory estoppel. For example, Palo Verde must be decommissioned and the site restored by federal law, so the removal costs associated with decommissioning Palo Verde are an ARO under SFAS No. 143. According to the Statement, such AROs are to be recognized at fair value as incurred and the costs associated with these legal obligations are to be capitalized as part of the related tangible long-lived assets. SFAS No. 143 specifically states, however, that it does not apply to removal costs that are not AROs, but rather result from a company's plan to dispose of assets.[1] These non-ARO costs would include removal costs associated with significant portions of the Company's distribution plant, certain generation plant, and even things like administrative

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[1] "This Statement does not apply to obligations that arise solely from a plan to dispose of a long-lived asset...." SFAS No. 143, ¶ 2.

buildings. For financial reporting purposes, removal costs for non-ARO assets are required to be expensed in the period incurred.

Q. HOW IS THE REMOVAL COST OR FAIR VALUE OF AN ARO DETERMINED UNDER SFAS NO. 143?

A. The fair value of a liability for an ARO is the amount at which that liability could be settled in a current transaction between willing parties. A present value technique is usually the best available technique to estimate the fair value of an ARO liability. This involves estimating future cash flows and then discounting the cash flows back to today using a risk-free rate adjusted for credit. However, this method requires an assumption that a third-party contractor is used. Because of this assumption, certain contractor costs such as profits and overheads must be factored into the fair value calculation. SFAS No. 143 also requires an entity to recognize period-to-period changes in the liability for an ARO resulting from the passage of time.

Q. GIVEN THIS BACKGROUND, WHAT WOULD BE THE IMPLICATIONS TO RATEPAYERS OF USING SFAS NO. 143 FOR RATEMAKING PURPOSES?

A. There are two major implications. First, if a company performs removal activities itself, customers would overpay for removal costs while the asset is in service, yet the overpayment would be returned to future customers only after the removal of the asset is complete, which could be 10 years or longer after an asset is taken out of service. If the liability turns out to be overstated for third-party profits and overheads that are not actually incurred, these accrued excess removal costs are recognized as a gain in the income statement at the end of the removal period. Second, SFAS No. 143 recognizes an annual expense that increases year by year due to the compounding of interest. Thus, customers in the early years of an asset's life would pay less than a pro rata share of the removal costs while customers in the later years would pay more than a pro rata share.

Q. WOULD ACCOUNTING FOR REMOVAL COSTS PURSUANT TO SFAS NO. 143 OVERSTATE REMOVAL COSTS DURING THE SERVICE LIVE OF PALO VERDE?

A. Yes. Palo Verde is a good example of why the required assumptions for SFAS No. 143 are not good assumptions for ratemaking purposes. The Company plans to internally manage the decommissioning activities for Palo Verde. This assumption was included in the decommissioning cost study prepared by TLG and is discussed in Mr. Thomas S. LaGuardia's rebuttal testimony. SFAS No. 143, however, requires companies to accrue a cost level that assumes an independent third party does the work, even if the company's stated intent is to manage the decommissioning activities internally. As a result, APS would have to increase the removal costs in the decommissioning study by about $80 million to include profits and other costs that would be charged by a third party contractor. The purpose of SFAS No. 143 is to help the financial community by taking a balance sheet disclosure approach regarding removal costs, as opposed to a cost-of-service approach which has a much different focus.

Q. IS SFAS NO. 143 CONSISTENT WITH THE COMMISSION'S RULES FOR ACCOUNTING FOR REMOVAL COSTS?

A. No. If the Commission were to adopt SFAS No. 143 to address the recovery of removal costs in rates, the result would be discriminatory and cause either undue detriments or undue benefits to individual customers over time because of the timing difference in the recognition of removal expenses in the income statement. As I discussed earlier, it certainly would not be a rational or systematic manner of recovering removal costs for ratemaking purposes. It is also dramatically inconsistent with how the Commission historically has viewed cost responsibility for utility customers.

Q. WOULD THERE BE OTHER ADVERSE RESULTS IF THE COMMISSION ADOPTED SFAS NO. 143 FOR RATEMAKING PURPOSES?

A. Yes. Under Mr. Majoros's recommendation, the Commission would have to accept whatever amount is calculated, through the use of the required third-party removal assumption, and rely on APS' external auditors regarding compliance with the standard. It may also require significant additional involvement of the Commission and Staff, in reviewing ARO calculations, interest rate determinations, the calculation of annual accretion, ARO asset amortization expenses, and other issues. Such analyses could be required every year as AROs are added or updated by APS.

Q. IS THERE A WAY FOR REGULATORS TO ADDRESS THE TIMING DIFFERENCE BETWEEN FINANCIAL REPORTING UNDER SFAS NO. 143 AND REGULATORY RULES REGARDING RECOVERY OF COSTS?

A. Yes. Because ratemaking principles often diverge from GAAP, the FASB has adopted a standard to recognize these potential differences. SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" provides accounting guidance in situations where regulators provide for recovery of costs on a basis that differs from non-regulated companies. More specifically, SFAS No. 71 specifically acknowledges that a cost may be accounted for in a different manner from that required by another authoritative pronouncement. However, a company must receive assurance from the regulators that the incurred costs will be recovered. In such cases, the utility is to follow SFAS No. 71 because it reflects the economic effects of the rate-making process—effects not considered in other authoritative pronouncements.

Q. IS THE COMPANY REQUESTING AN ACCOUNTING ORDER FOR ASSET RETIREMENT OBLIGATIONS AS PERMITTED UNDER SFAS NO. 71 TO ENSURE COMPLIANCE WITH THE COMMISSION'S RULES AND ACCEPTED RATEMAKING PRACTICES?

A. Yes. The Company has historically recovered removal costs in compliance with the Commission's rules and, as a result of the new accounting standard that has been issued, is simply requesting an accounting order to continue to comply with the Commission's rules in the same manner. An accounting order ensures that APS will continue to recover removal costs in a systematic and rational way over the service life of the assets, as required by Rule 102. Such an accounting order also ensures that the Company will not overstate the Palo Verde (or other) decommissioning costs for third party contractor costs that are not expected to be incurred.

Q. HAVE OTHER COMMISSIONS ISSUED ACCOUNTING ORDERS TO MAKE IMPLEMENTATION OF SFAS NO. 143 REVENUE NEUTRAL FROM A RATEMAKING PERSPECTIVE?

A. Yes. Other state commissions have issued accounting orders similar to the accounting order APS is requesting. I have attached as Schedule LLR-1RB copies of several of these orders and underlying analyses. In Florida, where a rule was actually promulgated to codify the implementation of SFAS No. 143 and make its implementation revenue neutral, the Public Service Commission Staff wrote that

> Under SFAS 143 the year to year removal costs included in expenses may be higher or lower than they are currently. Staff believes that these removal costs should continue to be recorded in approximately equal amounts over the life of the asset...[The rule] gives companies the authority to record Regulatory Assets and Regulatory Liabilities to neutralize the expense impact of implementing SFAS 143 for financial reporting.

[Staff Memorandum, Docket No. 030304-PU (June 30, 2003).] Similarly, the Utah Public Service Commission granted Pacificorp an accounting order addressing

SFAS No. 143. In a memorandum supporting the Commission accounting order, the Utah Utilities Division Staff wrote:

> Invoking SFAS 71, a public utility is permitted to record a regulatory asset or liability for any differences between SFAS 143 and regulatory accounting, for asset retirement obligations, rather than recording such differences as a charge or credit to net income.

[Utah Division of Public Utilities Staff Memo (July 15, 2003) at 3.] Also, as I noted in the Summary of my rebuttal testimony, the Public Utility Commission of Oregon Staff opposed the use of SFAS No. 143 for ratemaking purposes for many of the same reasons that I discuss. In their memorandum detailing five key justifications for the Staff position, the Staff stated:

> SFAS 143 should not be used for ratemaking...

[Oregon Staff Memorandum in PPL UM 1088 (June 17, 2003).]

Q. MR. MAJOROS ASSERTS THAT THE COMPANY IS NOT IN COMPLIANCE WITH THE FERC ORDER 631. DO YOU AGREE?

A. Absolutely not. Mr. Majoros is simply wrong in his analysis of Order No. 631, which is discussed in more detail in Dr. White's rebuttal testimony. The fact that other state commissions are issuing the same revenue neutral accounting orders that APS is requesting in this case further confirms that he is wrong. APS complies with Order 631 in recording removal costs of both AROs and other retirement obligations ("non-legal retirement obligations"). For 2003, APS has accounted for removal costs that are non-legal retirement obligations separately within FERC account 108, and has disclosed these costs in the audited financial statements filed with the Securities and Exchange Commission. This separate accounting is directed by FERC Order No. 631, which states "we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify…" The accrual for removal costs that are non-legal retirement obligations is included in the depreciation rates, also as allowed in Order 631. Order 631 provides that "removal costs that are not asset retirement obligations are included as a current component of the depreciation expense and recorded in accumulated depreciation." I would also note that Order 631 specifically states that "[t]he Commission did not propose any changes to its existing accounting requirements for costs of removal for non-legal retirement obligations." If Mr. Majoros believes that the Company is not in compliance, he should raise his concerns with FERC, the regulatory body that issued the order, rather than attempt to present an incorrect and flawed argument in this proceeding.

Q. DID MR. MAJOROS ADDRESS APS' REQUEST TO AMORTIZE CERTAIN GENERAL PLANT ACCOUNTS INSTEAD OF DEPRECIATING THE ASSETS AS REQUESTED BY APS?

A. No. Apparently, Mr. Majoros did not accept APS' request to amortize certain general plant accounts. He chose, instead, to lump them with other depreciated property. As I stated in my direct testimony, these accounts have a large volume of activity and low unit costs compared to other electric accounts. The effort and associated cost required to unitize additions, as well as periodically inventory equipment and determine amounts to be retired, is disproportionate to the original cost of the equipment when compared to other electric plant accounts. As a result, APS is requesting to amortize instead of depreciate these assets. FERC has approved this change for other utilities. For example, in a letter order to Louisville Gas and Electric Company ("LGE"), FERC ordered:

> LGE indicates that the change would be applicable to additions and retirements that are high in volume and low in unit cost.
>
> You state that the approval of this proposal will provide for the timely retirement of fully depreciated assets and eliminate the costly

> recording and tracking of many separate records in the Continuing Property Records Ledger.
>
> LGE's request is approved.

FERC Letter Order in Docket AC96-03-000 (June 4, 1996).

IV. LEAD-LAG STUDY AND CASH WORKING CAPITAL.

A. INCLUSION OF "OTHER REVENUE ITEMS"

Q. HAVE YOU REVIEWED STAFF'S TESTIMONY AND EXHIBITS RELATING TO WORKING CAPITAL?

A. Yes. Staff witness Carver discusses working capital issues in his testimony and shows his recalculation and update of the Company's working capital requirement in his Schedule B-7. One of the most significant changes he made to the Company's lead-lag study was the exclusion of certain revenue items, including depreciation expense and deferred taxes, which reduces the cash working capital allowance by $74.8 million.

Q. WHAT IS MR. CARVER'S POSITION ON THESE REVENUE ITEMS BEING INCLUDED IN THE LEAD-LAG STUDY?

A. Mr. Carver simply rejects out of hand their inclusion in the Company's lead-lag study. His position is that these items represent elements of cost of service that do not require a current period cash payment. He attempts to offer prior Commission decisions as his authority but does not conduct any analysis of whether these precedents should be applied in this case nor does he critique the rationale that other commissions and accounting professionals provide when they include these amounts in lead-lag studies. Mr. Rigsby, RUCO's witness, also submits a similar analysis that is flawed for essentially the same reason.

Q. WHAT IS YOUR RESPONSE TO MR. CARVER'S AND MR. RIGSBY'S POSITION THAT THESE OTHER REVENUE ITEMS SHOULD BE EXCLUDED FROM THE LEAD-LAG STUDY?

A. I strongly disagree with their over-simplified analyses and their assertions that prior Commission decisions on this issue should be followed without further analysis. For APS, it has been sixteen years since this issue was considered. The Company believes that it is time for the Commission to revisit the analysis of how cash working capital is determined and reconcile that with the underlying corporate and regulatory policy purposes for such a rate base item.

Q. HOW ARE STAFF'S AND RUCO'S WITNESSES OVERSIMPLIFYING THIS ISSUE?

A. Both witnesses argue that depreciation, amortization and deferred tax expenses are not "cash" items and therefore should not be included in "cash working capital." Mr. Carver argues that these items should be excluded from the lead-lag study because the cash transaction has already occurred, no periodic cash outlay is required, and therefore no investment in working capital is required. Mr. Carver and Mr. Rigsby inaccurately use the term "non-cash" expenses to refer to depreciation, amortization and deferred tax expenses. The term "non-cash" expenses is misleading in that it suggests that there is or was no cash outlay by investors, which is simply not true.

Depreciation expense, for example, constitutes the required "return of" capital previously invested on a cash basis in plant and equipment which forms a major part of the Company's rate base, and is reduced by the accumulated depreciation. As soon as the depreciation expense is booked, the amount of that expense is credited to the depreciation reserve. Net plant—and the rate base—is reduced, thus ending the investors' right to earn a return on that portion of the investment. However, the investor must wait to receive the return-of-capital cash payment of the depreciation expense in the form of utility revenues from customers. It is this lag from the "payment" by the Company of the depreciation expense to the collection of that amount from customers that creates a need to reflect the other revenue item somewhere in the Company's rate base. Whether it is considered part of "cash working capital" or a separate line item in the working capital component of rate base is irrelevant to the rationale for including it somewhere.

Similarly, deferred taxes are initially created to reflect the tax impact of timing differences between book income for financial reporting purposes and taxable income used to calculate current taxes to be paid to the Internal Revenue Service and other taxing authorities, with depreciation expense representing the main cause of the difference. If taxable income is less than book income, the tax effect of the difference is shown on the income statement as deferred tax expense with an offsetting amount reflected on the balance sheet which is deducted from rate base. Deferred taxes can be either a charge or a credit to expense on the income statement. If it is a charge (taxable income is less than book income), then it represents an expense on the income statement and is passed on to customers. An offsetting amount is reflected on the balance sheet and is reduced from rate base. However, there is a lag in the recovery of the deferred tax expense from customers, and just like depreciation expense, an amount equal to the unrecovered revenues at the end of test year must be included in the lead-lag study. APS initially submitted a deferred tax charge on its lead-lag study, but has accepted Staff's changes to current and deferred tax expense and revised the deferred tax number to a credit. This results in a reduction to cash working capital of $24.1 million which is discussed later in my testimony.

Q. IS APS' REQUEST TO INCLUDE THESE OTHER REVENUE ITEMS IN THE LEAD LAG STUDY UNPRECEDENTED OR OUT-OF-LINE WITH OTHER COMMISSIONS' TREATMENT OF THE ISSUE?

A. No. I believe that the accounting profession and other state commissions are now recognizing the appropriateness of reflecting these items somewhere in a utility's rate base. For example, Robert Hahne and Gregory Aliff in their treatise *Accounting for Public Utilities* state:

> Including the depreciation expense in the lead-lag study, and assigning thereto a zero payment lag, recognizes that investor funding has occurred, but that it has not yet been recovered. Even though the depreciation expense is recorded as a period cost, the recovery will be delayed for the duration of the billing lag. In the interim, continued investor funding is required.

Generally, the California Public Utilities Commission includes these items in lead lag studies. Under their Standard Practice U-16, the Commission wrote:

> Since book depreciation expense is occurring uniformly day by day and accumulated depreciation is deducted from rate base, the practice is to include depreciation provisions at zero lag days.

See California Public Utilities Commission, Standard U-16. In Tennessee, the commission wrote in a 1997 order that:

> [T]he Directors recognized that including the Depreciation Expense in the Lead/Lag study at zero (0) Lag Days is necessary to recognize that investor funding has occurred, but was not yet recovered.

See Order, Petition of Chattanooga Gas Co. (Docket No. 97-00982). Other states, including South Carolina, New Jersey and Connecticut recently have approved lead-lag studies that include so-called "non-cash items" using the same rationale for the need to recognize the lag from booking the expense to recovery of the expense from customers.

Q. DO ALL STATES REQUIRE LEAD-LAG STUDIES TO DETERMINE CASH WORKING CAPITAL REQUIREMENTS?

A. No. Many states have rejected altogether the use of costly and overly controversial lead-lag studies in favor of formula approaches to recognize cash working capital requirements. One such formula is the 1/8th formula (setting cash working capital at 1/8th of operating and maintenance expense less purchased power expenses). If applied to APS, this formula would result in a cash working capital requirement of approximately $62 million, which was relatively close to the $54.1 million cash working capital allowance that APS calculated in its Application but is significantly higher than the revised cash working capital request that I discuss later in my testimony. I note this not because APS is requesting that the Commission adopt a formula approach for cash working capital in this case. Rather, this shows that states using a formula approach also would not support the negative cash working capital levels that typically occur when critical expenses like depreciation and deferred taxes are carved out of lead-lag studies.

Q. WHY SHOULD THE COMMISSION FOLLOW THESE OTHER JURISDICTIONS AND AUTHORITIES NOW?

A. Most importantly, recognizing the lag in collecting funds after booking depreciation and deferred tax expense is fundamentally consistent with how rate base is valued for ratemaking purposes and thus results in a revenue requirement for the Company that is calculated in a consistent manner. While every other rate base component, both assets and liabilities, and all operating revenues and expenses are developed on an "accrual" basis, cash working capital is reflected on a "cash" basis—resulting in a mix of accounting methods that would be abhorred in any other context. This inconsistency results in a self-fulfilling outcome that has essentially become the norm when using a lead-lag study without including major expense items like depreciation and deferred taxes, where virtually all utilities end up with a negative cash working capital and a reduction to its tangible rate base. Considering that APS does not bill for services it provides until after it is provided, I find it incredulous that APS needs no working capital to operate its business, and instead has a "float" provided by customers upon which it can finance power plants, transmission lines and other permanent infrastructure. This unlikely result means that working capital needs for APS would be more akin to those of an insurance company collecting premiums from its customers prior to paying out insurance claims as its cost of service. More importantly, from a ratemaking standpoint, this approach fails to provide investors with a fair return on all of their investment because these expenses are removed from rate base without recognition of the delay in collecting the associated funds from customers.

Q. ARE OTHER ITEMS IN THE LEAD-LAG STUDY TREATED SIMILARLY TO APS' PROPOSAL FOR "OTHER REVENUE ITEMS"?

A. Fuel expense is treated similarly to how APS believes the Commission should treat depreciation expense. Specifically, fuel is initially charged to a balance sheet inventory account with payment made sometime later. As fuel is consumed, journal entries typically record the transfer of costs from fuel inventory to fuel expense. Both depreciation and fuel involve initial charges and payments recorded on the balance sheet that are reflected in rate base, and both involve the use of journal entries to record the applicable expenses. Although Staff and RUCO do not question that fuel expense should be included in the lead lag study, they inconsistently argue that depreciation expense should not be included. It is this type of contradiction in lead-lag study methodology that Staff and RUCO are using to unreasonably reduce APS' rate base.

Q. HOW DID YOU CALCULATE THE AMOUNT OF THESE OTHER REVENUE ITEMS WHEN PREPARING THE LEAD -LAG STUDY?

A. The calculation of the other revenue lag items was made by determining the amount of the related cost of service/revenue requirement item that remained unpaid by customers at the end of the test year. This was done by (1) calculating the daily cost of service/revenue requirement amount, and (2) multiplying the result by the average number of days of cost of service not yet paid for by the customers at the end of test year. This amount is then included in the lead-lag study with a zero lag to reflect the necessary rate base addition that offsets the deductions to rate base that had not yet been recovered from customers as of the end of the test year.

Q. MR. CARVER ALSO ASSERTS THAT THE DEPRECIATION EXPENSE LAG IS ZERO, BUT THAT CASH WORKING CAPITAL FAILS TO ACCOUNT FOR THE DELAYED CASH OUTFLOWS IN PAYMENT OF CONSTRUCTION COSTS. DO YOU AGREE WITH THIS?

A. No. This statement shows that Mr. Carver is ignoring the purpose of a lead-lag study. As I explained earlier, APS is only seeking to recover the amount of depreciation expense that is in accounts receivable at the end of the test year. The lead-lag study is based on test-year depreciation expense, not future expense. Because APS does not include construction work in progress in plant in service balance, it is not part of the Company's rate base. The amount APS has included in working capital is based only on capital expenditures its shareholders have made in the past and which are reflected in rate base.

Q. MR. CARVER ALSO ARGUES THAT ALTHOUGH DEPRECIATION AND DEFERRED TAX EXPENSES SHOULD BE EXCLUDED FROM THE LEAD LAG STUDY, THE STUDY SHOULD RECOGNIZE INTEREST EXPENSE TO FURTHER DEPRESS THE CASH WORKING CAPITAL REQUIREMENT. DO YOU AGREE?

A. No. This is another example of how a lead-lag study can be misused to inequitably treat the Company. Mr. Carver asserts that "fairness" requires that the lag associated with interest expense (the difference between when funds are collected and paid to bondholders) be used to further depress cash working capital. He claims that this is "fair" because interest expense is just as much a part of the revenue requirement as operating expenses like fuel and payroll. It is certainly clear that in the regulatory process, long-term debt interest is part of investor returns paid from operating income. Operating income—the returns for investors—is the money left over after all expenses, depreciation, amortization, and taxes have been paid. This operating income is the property of the equity investor and is earned at the time of service. At the point it is earned, it is up to the equity investors to decide to pay contractual interest and decide whether to obtain further capital for the Company in the form of long-term debt (or preferred stock). But the risk of meeting the contractual interest and dividend payments, as well as earning an overall return, belongs to the equity investor, not ratepayers. Thus it is <u>unfair</u> to essentially appropriate the interest expense earned by investors and use it to further depress the Company's rate base.

B. SALES TAXES AND PAYROLL TAXES.

Q. DO YOU AGREE WITH MR. CARVER'S TESTIMONY RELATING TO INCLUSION OF ARIZONA SALES TAX IN THE LEAD-LAG STUDY?

A. No. APS consistently includes only operating expenses, and sales tax is not an operating expense. However, if Staff's recommendation to include sales tax were to be accepted, the revenue lag for sales tax should be consistent with that for all operating expenses. Under Mr. Carver's approach, the revenue lag for sales tax would only be calculated from the date of billing to the date of collection. Using the revenue lag originally submitted by APS of 41.81069 days results in an increase to cash working capital of $562,000.

Q. MR. CARVER ALSO ASKS THE COMPANY TO EXPLAIN WHETHER PAYROLL TAXES SHOULD FURTHER REDUCE CASH WORKING CAPITAL. IS THIS A VALID CONCERN?

A. No. The employer share of FICA and Medicare payroll taxes were properly accounted for in the lead-lag study, and were listed under O&M expense as "Payroll Taxes" (Schedule LLR-3, line 19). The employee share of payroll taxes was included in the gross payroll amount (Schedule LLR-3, line 15). APS did not break out employee payroll tax withholdings as separate O&M expenses. Also, all significant employee withholdings are remitted to the appropriate government authority essentially at the time payroll is paid. Because the funds withheld for the employee share of payroll taxes are essentially paid out immediately and because APS acts solely as a conduit for the taxing authority, it was not necessary to include these as separate O&M items to reflect a different lag.

C. OTHER LEAD-LAG STUDY ISSUES.

Q. MR. CARVER RECALCULATED THE REVENUE LAG USING A DAILY ACCOUNTS RECEIVABLE BALANCE INSTEAD OF MONTH-END BALANCES IN CALCULATING OF THE COLLECTION LAG. DO YOU BELIEVE THAT THIS IS APPROPRIATE?

A. No. APS used month-end balances, as it has consistently done with previous lead-lag studies accepted by the Commission, because month-end balances are the most readily accessible financial information in the Company's accounting systems. Specifically, APS does not maintain daily balances in the ordinary course of business. To determine the daily balances for the samples that were requested in data requests from Staff, APS had to develop complex queries to derive these daily balances. A lead-lag study is a very complex analysis and requires a substantial number of man-hours to prepare, so it is both necessary and appropriate to make reasonable assumptions at various places in the study.

Q. WHY DO YOU BELIEVE THAT MR. CARVER PROPOSED USING DAILY BALANCES?

A. I assume that he used this approach because in this case and with this particular study it resulted in a lower collection lag and thus further reduced APS' requested cash working capital allowance. Interestingly, I believe that his argument to use a more complex methodology rather than the month-end method chosen by APS contradicts prior testimony that he recently submitted on behalf of the ratepayer advocate in California in which he criticized the complexity of lead-lag studies. Mr. Carver himself cited a California Public Utilities Commission decision as an illustration:

> **Q16. Has the [CPUC] previously expressed concern over the complexity and controversy sometimes surrounding the subject of cash working capital?**
>
> **A16.** Yes. In a 1996 GRC decision involving Pacific Gas & Electric, the Commission provided the following commentary, indicating that the calculation of working cash may warrant simplification:
>
>> Working cash calculations require a level of precision, complexity and sometimes controversy which are out of proportion to the significance of working cash in the greater scheme of regulation. This is one area where a simple but intuitive calculation, even lacking in imprecision, would be an improvement over the current circumstance. If we revisit this issue in a future case, we hope the parties will propose simpler methods for determining working cash.
>
> [D.95-12-055, 63 CPUC2d 570, 617]

(Opening Testimony of Steven Carver in CPUC Proceeding R.01-09-001/I.01-09-002.) APS used the month-end balances that are standard in its accounting practices, and I do not see any reason to modify that approach simply because in this case choosing a daily balance produced a lower number.

Q. MR. RIGSBY INCLUDES PRO FORMA ADJUSTMENTS IN HIS ANALYSIS OF TEST YEAR LEVEL OPERATING EXPENSES. DO YOU AGREE WITH HIS PROPOSAL?

A. No. The types of adjustments involved are not significant enough to warrant the additional expense and complexity to adjust the lead-lag study. In fact, in addressing adjustments to test year expense levels, Staff witness Carver states on page 20 of his direct testimony, "When <u>feasible and significant</u> to the outcome, <u>material</u> ratemaking adjustments to test year expense levels should be recognized in the lead-lag results…" (Emphasis added.) Staff did not include pro forma adjustments in its recommendations.

Q. MR. CARVER PROPOSES SEVERAL OTHER CHANGES WITH RESPECT TO THE LEAD-LAG STUDY. ARE THERE ANY THAT YOU AGREE WITH?

A. Yes. Mr. Carver pointed out several changes that the Company accepts. Specifically, these are (1) change the coal delivery dates, (2) change the "minus 1" in a formula, (3) change the lag days for fuel oil, (4) change the credit card expense lag, and (5) change the pension and OPEB expense amount. These five adjustments decrease APS' cash working capital by $273,000. I also do not oppose Mr. Carver's use of normalized income tax levels for the test year. This adjustment reduces APS' cash working capital requirement by $10.6 million. The change in deferred taxes also reduces the "other revenue items" portion of cash working capital by $24.1 million.

Q. AFTER CONSIDERING THE ISSUES MR. CARVER RAISED THAT APS DOES NOT OPPOSE, CAN YOU SUMMARIZE THE COMPANY'S REVISED CASH WORKING CAPITAL REQUEST?

A. The changes to the Company's proposal for cash working capital, showing the modifications that APS does not oppose from the testimony of other parties, is summarized on Schedule LLR-2RB. The total changes reflected in this Schedule result in a revised cash working capital request of $19.7 million, which is a reduction of $34.4 million from the original request in the Application (Schedule B-5, Line 1).

Q. COULD YOU SUMMARIZE WHY YOU BELIEVE THIS REVISED CASH WORKING CAPITAL REQUEST IS APPROPRIATE?

A. Yes. APS prepared a valid lead-lag study, using reasonable assumptions. Lead-lag studies are extremely complex, and APS accepted several changes to the study proposed by Staff. Some of Staff's proposals, however, require layering on yet more complexity, result in inconsistent treatment of similar items, and are chosen because these assumptions unreasonably lower the Company's cash working capital request. APS' request is more than reasonable when compared to many other jurisdictions that use "rule of thumb" approaches like the 1/8th rule that would result in a substantially higher cash working capital allowance. APS also disagrees with the proposed exclusion by Staff and RUCO of "other revenue items" such as depreciation expense and deferred tax expense which ignores the fact that investors are being deprived of an opportunity to earn a fair return on their investment for the lag period. Finally, APS disagrees with the equally unfair treatment of interest expense, where operating income earned by investors is appropriated after it becomes the property of investors to further depress the Company's rate base.

V. INDEPENDENT SPENT FUEL STORAGE INSTALLATION

Q. WHAT DOES RUCO PROPOSE FOR THE RATEMAKING TREATMENT OF ISFSI?

A. Ms. Diaz Cortez takes issue with one part of the Company's proposal for the treatment of ISFSI, which are costs associated with interim storage of spent nuclear fuel while the federal government finishes siting and constructing a permanent storage facility for these materials. Ms. Diaz Cortez agrees that amortization expense and on-going costs associated with ISFSI should be recovered, but she disagrees that the deferred balance of ISFSI accruals should be ratebased. She argues that the deferred balances of ISFSI accruals are "mere accounting accruals" and do not represent actual expenditures by investors.

Q. DO YOU AGREE WITH RUCO'S RECOMMENDATION REGARDING THE RATE BASE TREATMENT OF ISFSI?

A. No, although I agree with Ms. Diaz Cortez that only the actual costs incurred should be included in the rate base and earn a rate of return. That is what the Company has proposed. RUCO's recommendation fails to consider the required additional accounting entries, the accumulated removal for ISFSI and its related impact of deferred taxes, used by APS that reduce the $50.4 million of deferred ISFSI accruals, resulting in only the amounts actually paid by investors being reflected in rate base. Additionally, the adjustment proposed by Ms. Diaz Cortez has the incorrect amount of deferred tax related to the regulatory asset and also does not consider the interest synchronization.

Q. PLEASE EXPLAIN THESE OFFSETTING ACCOUNTING ENTRIES.

A. APS' rate base at the end of the test year correctly reflects $3.9 million for ISFSI, net of deferred taxes. APS' rate base includes an addition for the ISFSI regulatory asset of $50.4 million and a reduction to the rate base for the net accumulated ISFSI removal accrual of $43.9 million included in Nuclear Fuel Inventory, a component of the Allowance for Working Capital. These entries are shown in Schedule LLR-3RB.

Q. PLEASE EXPLAIN HOW THE ACTUAL EXPENDITURES FOR ISFSI ARE INCLUDED IN RATE BASE?

A. As actual expenditures are incurred, these costs are charged to the ISFSI accumulated removal accrual. This net accumulated removal accrual is lower than the gross cost accrued, as reflected in the regulatory asset. The difference between the regulatory asset and the accumulated removal for ISFSI represent the cash expenditure by APS. APS is entitled to earn a return on this investment. Schedule LLR-3RB, which references lines numbers from other APS schedules, shows how these expenditures and associated regulatory assets and deferred taxes were addressed in APS' Application.

Q. DOES MS. DIAZ CORTEZ'S PROPOSAL ALLOW APS TO EARN A RETURN ON ITS CASH EXPENSES ASSOCIATED WITH ISFSI?

A. No. By erroneously excluding only the deferred balance and not also removing the deduction to the Allowance for Working Capital and accounting for deferred taxes, Ms. Diaz Cortez's proposal would not only prevent APS from earning a return on the money actually invested in ISFSI, it would eliminate more than $46 million of the Company's rate base without justification.

VI. <u>RCND CALCULATIONS</u>

Q. HAVE YOU DEVELOPED REVISED RCND CALCULATIONS FOR VARIOUS RATE BASE ADJUSTMENTS PROPOSED OR ACCEPTED BY THE COMPANY?

A. Yes. In my direct testimony I sponsored the Company's Reconstruction Cost New ("RCN") and Reconstruction Cost New Less Depreciation ("RCND") study. In Schedule LLR-4RB, I present the RCN and RCND amounts for the rate base adjustments that are addressed in APS' rebuttal testimony.

Q. IS THE METHODOLOGY BY WHICH YOU CALCULATED THE RCN AND RCND AMOUNTS THE SAME AS PRESENTED IN YOUR DIRECT TESTIMONY?

A. Yes. The calculations of these RCN and RCND amounts follow the same methods that I discussed at pages 3 through 9 of my Direct Testimony.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

1490153

Schedule LL2-1RB

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

RECEIVED-FPSC
03 MAY 21 PM 3:29
COMMISSION CLERK

DATE: MAY 22, 2003

TO: DIRECTOR, DIVISION OF THE COMMISSION CLERK & ADMINISTRATIVE SERVICES (BAYÓ)

FROM: OFFICE OF THE GENERAL COUNSEL (STERN) MKS DS
DIVISION OF ECONOMIC REGULATION (ROMIG, HEWITT) CBH DM

RE: DOCKET NO. 030304-PU - PROPOSED ADOPTION OF RULE 25-14.014, F.A.C., ACCOUNTING FOR ASSET RETIREMENT OBLIGATIONS UNDER SFAS 143.

AGENDA: 06/03/03 - REGULAR AGENDA - INTERESTED PERSONS MAY PARTICIPATE

CRITICAL DATES: NONE

SPECIAL INSTRUCTIONS: NONE

FILE NAME AND LOCATION: S:\PSC\GCL\WP\030304.RCM

DISCUSSION OF ISSUES

ISSUE 1: Should the Commission propose Rule 25-14.014, Florida Administrative Code, titled "Accounting for Asset Retirement Obligations Under SFAS 143"?

RECOMMENDATION: Yes, the Commission should propose the rule as shown in the attachment to this recommendation.

STAFF ANALYSIS: The Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards 143 (SFAS 143), Accounting for Retirement Obligations, in June 2001. This Statement is effective for financial statements issued for fiscal years beginning after June 15, 2002. SFAS 143 changes the method of accounting for the cost of removal of long-lived assets. Currently, a regulated company in Florida records the cost of removal in approximate equal amounts over the life of the asset to which it relates. SFAS 143 applies primarily to the

DOCUMENT NUMBER-DATE
04589 MAY 21 8
FPSC-COMMISSION CLERK

decommissioning of nuclear plants. Under SFAS 143 the year to year removal costs included in expenses may be higher or lower than they are currently. Staff believes that these removal costs should continue to be recorded in approximate equal amounts over the life of the asset. Rule 25-14.014 is proposed to accomplish this uniformity. If the Commission does not approve a rule to address SFAS 143, then each company will be required to maintain one set of books for financial purposes and a different set of books for regulatory purposes. This rule will benefit regulated companies since they will only be required to keep one set of books.

Proposed Rule 25-14.014 dictates how a regulated company accounts for Asset Retirement Obligations under SFAS 143 on its books for financial purposes and for regulatory purposes. It gives companies the authority to record Regulatory Assets and Regulatory Liabilities to neutralize the expense impact of implementing SFAS 143 for financial reporting. The Rule also ensures that the effect of SFAS 143 on financial statements will be consistent for all companies and will not alter earnings from what they would be without SFAS 143.

The Notice of Proposed Rule Development was published in the January 31, 2003 issue of the Florida Administrative Weekly. A workshop was not requested.

STATUTORY AUTHORITY

Section 350.127(2), Florida Statutes, grants the Commission rulemaking authority. The statutes being implemented by this proposed rule are Sections 366.05(1), 364.03 and 367.121(1)(a), Florida Statutes. These statutes grant the Commission authority to prescribe fair and reasonable rates for regulated, public gas and electric utilities, telecommunications companies, and water and wastewater utilities, respectively. This rule will affect rates beneficially because, by allowing utilities to keep one set of books, it will reduce administrative costs. Reducing administrative costs will keep rates reasonable.

STATEMENT OF ESTIMATED REGULATORY COSTS

Regulated corporations must comply with SFAS 143 and should only have minor costs complying with the proposed rule. Therefore, a Statement of Estimated Regulatory Costs is not necessary.

ISSUE 2: Should this docket be closed?

RECOMMENDATION: Yes, if no requests for hearing or comments are filed, the rule as proposed should be filed for adoption with the Secretary of State and the docket should be closed.

STAFF ANALYSIS: Unless comments or requests for hearing are filed, the rule as proposed may be filed with the Secretary of State without further Commission action. The docket may then be closed.

DOCKET NO. 030304-PU
DATE: May 22, 2003

25-14.014 Accounting for Asset Retirement Obligations Under SFAS 143.

(1) The Financial Accounting Standards Board issued Statement No. 143, Accounting for Asset Retirement Obligations (SFAS 143) in June 2001. The statement applies to legal obligations associated with the retirement of tangible, long-lived assets that result from the acquisition, construction, development or normal operation of a long-lived asset. For utilities required to implement SFAS 143, it shall be implemented in a manner such that the assets, liabilities and expenses created by SFAS 143 and the application of SFAS 143 shall be revenue neutral in the rate making process.

(2) Definitions. For purposes of this rule, the following definitions apply:

(a) "Accretion Expense." The concurrent cost that is recorded as an operating item in the statement of income to account for the passage of time and the resulting period-to-period increase in the Asset Retirement Obligation.

(b) "Asset Retirement Cost." The amount capitalized that increases the carrying amount of the long-lived asset when a liability for an Asset Retirement Obligation is recognized.

(c) "Asset Retirement Obligation." An obligation associated with the retirement of a tangible long-lived asset.

CODING: Words underlined are additions; words in ~~struck through~~ type are deletions from existing law.

(3) Pursuant to SFAS 143, each utility shall recognize the fair value of a liability for an Asset Retirement Obligation in the period in which it is incurred if a reasonable estimate of the fair value can be made. If a reasonable estimate of fair value cannot be made in the period the Asset Retirement Obligation is incurred, the liability shall be recognized when the reasonable estimate of fair value can be made. The fair value of the liability for an Asset Retirement Obligation is the amount at which that liability could be settled in a current transaction between willing parties, that is, other than in a forced or liquidation transaction. If quoted market prices are not available, the estimate of fair value shall be based on the best information available in the circumstances including prices for similar liabilities and the result of present value or other valuation techniques. The Asset Retirement Obligations shall be kept by function and recorded in separate subaccounts.

(4) Upon initial recognition of a liability for an Asset Retirement Obligation, the utility shall capitalize an Asset Retirement Cost by increasing the carrying amount of the long-lived assets by the same amount as the liability. The Asset Retirement Cost shall be kept by function and recorded in a separate subaccount as intangible plant. The utility shall subsequently

CODING: Words underlined are additions; words in ~~struck through~~ type are deletions from existing law.

allocate that Asset Retirement Cost to expense over its useful life. The expense shall be recorded in a separate subaccount.

(5) Asset Retirement Costs do not qualify for Allowance for Funds Used During Construction.

(6) Pursuant to SFAS 143, in periods subsequent to the initial measurement, a utility shall recognize period-to-period changes in the liability for an Asset Retirement Obligation resulting from accretion or revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

(a) A utility shall measure the accretion cost in the liability for an Asset Retirement Obligation due to passage of time by applying the interest method of allocation to the amount of the liability at the beginning of the period. This amount shall be recognized as an increase in the carrying amount of the liability.

(b) The accretion expense shall be recorded in a separate subaccount.

(c) Revisions to a previously recorded Asset Retirement Obligation will result from changes in the assumptions used to estimate the cash flows required to settle the Asset Retirement Obligation, including changes in estimated probabilities, amounts, and timing of the settlement of the Asset Retirement Obligation, as well as changes in the legal requirements of an obligation. Upward revisions to the undiscounted estimated cash flows shall be treated as a new liability and discounted at the current rate. Downward revisions will result in a reduction of the Asset Retirement Obligation. The amount of the liability to be removed shall be discounted at the rate that was used at the time the obligation was originally recorded. The concurrent debit or credit shall be made to the Asset Retirement Cost.

(7) Differences between amounts prescribed by the Commission and those used in the application of SFAS 143 shall be recorded as Regulatory Liabilities or Regulatory Assets in separate subaccounts.

(8) The Regulatory Debit and Regulatory Credit accounts shall be used to record the differences between the Commission prescribed amounts and the amounts which are reported as expense under SFAS 143.

(9) Each utility shall keep records supporting the calculation and the assumptions used in the determination of the Asset Retirement Obligation and the related Asset Retirement Cost and the related Regulatory Assets and Regulatory Liabilities established in accordance with this rule and the implementation of SFAS 143.

(10) If a utility is not required to establish an Asset Retirement Obligation for an asset or group of assets, the cost of

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removal shall continue to be included in the calculation of the depreciation expense and accumulated depreciation.

Specific Authority: 350.127(2) F.S.

Law Implemented: 364.03, 364.035(5), 366.05(1), 367.121(1)(a) F.S.

History: New .

CODING: Words underlined are additions; words in ~~struck through~~ type are deletions from existing law.

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the matter of the Application of PacifiCorp for an Accounting Order Regarding Treatment of Certain Asset Retirement Obligations	))))	DOCKET NO. 03-035-13 ACCOUNTING ORDER

ISSUED: August 13, 2003

By The Commission:

On May 27, 2003, PacifiCorp, dba Utah Power and Light Company (PacifiCorp), filed an Application seeking authorization to record, as a regulatory asset or regulatory liability, the cumulative financial statement impact resulting from PacifiCorp's implementation of Statement of Financial Accounting Standards (SFAS) 143 and to record on an ongoing basis, as a regulatory asset or a regulatory liability, an amount equal to the difference between the annual SFAS 143 accretion and depreciation expense and the annual depreciation expenses based on Utah Public Service Commission approved depreciation rates and coal mine reclamation accruals.

In June, 2001, the Financial Accounting Standards Board (FASB) issued SFAS 143, Accounting for Asset Retirement Obligations, effective for fiscal years beginning after June 15, 2002. SFAS 143 addresses the financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. The FASB issued SFAS 143 to eliminate inconsistencies in accounting practices for asset retirement obligations. SFAS 143 is directed to obligations that meet the definition of a liability, but are not recognized as such on financial statements when the liability is incurred or, if a liability is recognized, it is not measured or presented in a consistent manner.

PacifiCorp will be implementing SFAS 143 in fiscal year 2004. PacifiCorp's current financial and ratemaking accounting method differs from SFAS 143's approach. After a review, PacifiCorp has determined that it will need to record asset retirement obligations under SFAS 143 for certain generation and mining assets. PacifiCorp has also identified asset retirement obligations for transmission and distribution assets; but the timing of those obligations is indeterminate and the liability cannot be measured and recorded at this time. SFAS 143 recognizes that differences may exist between its requirements and asset retirement obligations for regulatory purposes. Regulated entities subject to SFAS 71, Accounting for the Effects of Certain Types of Regulation, are able to recognize any differences between the two methods as a regulatory asset or liability, subject to SFAS 71 provisions. In order to reconcile the requirements of SFAS 143 and the regulatory accounting practices, PacifiCorp seeks authorization to record any difference between the annual SFAS 143 accretion and depreciation expenses and the annual Commission-approved depreciation rates and coal mine reclamation accruals as a regulatory asset or a regulatory liability.

On July 17, 2003, the Division of Public Utilities (DPU) filed its Memorandum describing its review of the Application and recommending that the Commission grant the application and authorize the accounting method sought by PacifiCorp. On July 25, 2003, the Committee of Consumer Services (CCS) submitted its Memorandum recommending approval as well. In addition to supporting the company's proposed accounting methodology, both the DPU and the CCS recommend that PacifiCorp be required, in its semi-annual results of operations reports and in general rate case filings, to provide information on all journal entries made under the requirements of SFAS 143 and information supporting the determination of the regulatory assets and liabilities. Counsel for PacifiCorp has informed the Commission that the company does not oppose this latter DPU/CCS recommended reporting requirement.

Based upon the foregoing, the Commission will issue an accounting order authorizing the accounting practice sought by PacifiCorp. PacifiCorp stated that it will implement SFAS 143 with its 10-Q for the quarter ending June 30, 2003. It seeks authorization at the earliest opportunity. Because there appears to be no opposition or objection to the authorization, the Commission will proceed under Rule 110 and grant its order without hearing and waive the 20-day tentative period. The order will be final upon issuance.

FINAL ORDER

Wherefore, the Commission issues this Final Order authorizing PacifiCorp to implement SFAS 143 and account for applicable asset retirement obligations as requested in its Application and as recommended by the DPU and CCS.

Agency Review and Judicial Appeal

Pursuant to Utah Code 63-46b-12 and 54-7-15, agency review or rehearing of this order may be obtained by filing a request for review or rehearing with the Commission within 30 days after the issuance of the order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the Commission fails to grant a request for review or rehearing within 20 days after the filing of a request for review or rehearing, it is deemed denied. Judicial review of the Commission's final agency action may be obtained by filing a Petition for Review with the Utah Supreme Court within 30 days after final agency action. Any Petition for Review must comply with the requirements of Utah Code 63-46b-14, 63-46b-16 and the Utah Rules of Appellate Procedure.

DATED at Salt Lake City, Utah, this 13th day of August, 2003.

/s/ Ric Campbell, Chairman

/s/ Constance B. White, Commissioner

/s/ Ted Boyer, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary

GW #34754

ORDER NO. 03-455

ENTERED JUL 24 2003

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1088

In the Matter of	)	
	)	
PACIFIC POWER & LIGHT (dba	)	
PACIFICORP)	)	ORDER
	)	
Application for an Accounting Order	)	
Regarding Treatment of Certain Asset	)	
Retirement Obligations.	)	

DISPOSITION: APPLICATION APPROVED WITH CONDITION

On May 27, 2003, Pacific Power & Light (PacifiCorp) filed an application with the Public Utility Commission (Commission) requesting an accounting order authorizing PacifiCorp to 1) record, as a regulatory asset or a regulatory liability, the cumulative financial statement impact resulting from PacifiCorp's implementation of Statement of Financial Accounting Standards (SFAS) 143; and 2) record on an ongoing basis, as a regulatory asset or regulatory liability, an amount equal to the difference between the annual SFAS accretion and depreciation expenses and the annual depreciation expenses based on Commission-approved depreciation expense.

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS 143, *Accounting for Asset Retirement Obligations*, effective for fiscal years after June 15, 2002. Under SFAS 143, entities are required to recognize and account for certain asset retirement obligations in a manner different from the way that PacifiCorp has traditionally recognized and accounted for such costs. Staff's recommendation is attached as Appendix A and is incorporated by reference.

At its Public Meeting on June 15, 2003, the Commission adopted Staff's Recommendations and approved PacifiCorp's current request with one condition.

ORDER

IT IS ORDERED that:

1) Pacific Power & Light Company's accounting application is approved, subject to one condition.

2) At any time Pacific Power & Light Company files a results of operations report or general rate change, for a period of five years, Pacific Power & Light Company must provide the Public Utility Commission with all journal entries made under the requirements of SFAS 143 and any adjustments necessary to remove rate impacts of this accounting treatment.

Made, entered and effective ______________________________.

BY THE COMMISSION:

____

Becky Beier
Commission Secretary

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A party may appeal this order to a court pursuant to ORS 756.580.

ITEM NO. CA4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: July 15, 2003

REGULAR ____ **CONSENT** _X_ **EFFECTIVE DATE** ______ **April 1, 2003**

DATE: June 17, 2003

TO: John Savage through Lee Sparling and Ed Busch

FROM: Judy Johnson

SUBJECT: PACIFIC POWER & LIGHT: (Docket No. UM 1088) Requests Accounting Order Regarding Treatment of Certain Asset Retirement Obligations

SUMMARY RECOMMENDATION:

I recommend the Commission approve Pacific Power & Light Company's accounting application, with one condition.

DISCUSSION:

On May 27, 2003, Pacific Power & Light Company (PacifiCorp or company) filed an application requesting an accounting order authorizing the company to 1) record, as a regulatory asset or a regulatory liability, the cumulative financial statement impact resulting from the company's implementation of Statement of Financial Accounting Standards (SFAS) 143; and 2) record on an ongoing basis, as a regulatory asset or regulatory liability, an amount equal to the difference between the annual SFAS accretion and depreciation expenses and the annual depreciation expensed based on Commission-approved depreciation expense.

On June 2001, the Financial Accounting Standards Board (FASB) issued SFAS 143, *Accounting for Asset Retirement Obligations*, effective for fiscal years after June 15, 2002. Under SFAS 143, entities are required to recognize and account for certain asset retirement obligations in a manner different from the way that PacifiCorp has traditionally recognized and accounted for such costs.

Specifically, if a legally enforceable asset retirement obligation (ARO), as defined by SFAS 143, is deemed to exist, an entity must measure and record the liability for the ARO on its books at fair market value in the period during which the liability is incurred. At the time the liability is recorded, a corresponding and equivalent ARO asset is also recorded on the entity's books as part of the cost of the associated tangible asset. The ARO asset is then depreciated over the life of the associated tangible asset. In addition, accretion is added to the ARO liability annually to account for the time value of money, so that at the time of retirement the recorded ARO liability will be sufficient to provide the cash required to meet the legal obligation.

In addition to the forward-looking requirements of SFAS 143, entities are required to recognize the cumulative impact on their financial statements resulting from the implementation of SFAS 143. This cumulative impact amounts to a transition entry on the entity's books, so that in future years the financial statements will appear as if the requirements of SFAS 143 had always been followed. Neither the SFAS 143 transition entries nor the annual accounting entries will change the level of costs included in rates.

PacifiCorp is required to implement SFAS 143 in order to comply with Generally Accepted Accounting Principles. The company has determined that it will need to record AROs under SFAS 143 for certain generation and mining assets. The company has also identified AROs for transmission and distribution assets. However, the timing of those obligations is indeterminate and the liability cannot be measured and recorded at this time. There were no material AROs for general plant assets.

The company's proposed accounting treatment will use SFAS 143 for reporting on its financial statements, but retain its current methodology for ratemaking purposes. SFAS 143 recognizes that differences may exist between its requirements and the treatment of ARO costs for regulatory purposes and provides that a regulated entity subject to SFAS 71, *Accounting for the Effects of Certain Types of Regulation*, can recognize any differences between the two approaches as a regulatory asset or a regulatory liability, subject to the requirements of SFAS 71.

Under the accounting method currently used by the company for both financial reporting and ratemaking purposes, the cost of removing a tangible long-lived asset at retirement is included in the calculation of depreciation rates as negative salvage and is recovered over the useful life of the asset. Under this method, the accrued removal cost is included in Account 108, Accumulated Depreciation.

PacifiCorp believes, and Staff agrees, that it is not appropriate to apply the requirements of SFAS 143 in determining AROs for ratemaking purposes. Rather, the company believes, and Staff agrees, that AROs should continue to be established through traditional depreciation studies and recovered through the application of Commission-approved depreciation rates. SFAS 143 should not be used for ratemaking for several reasons detailed in the attachment to the Staff report.

Nothing in this application requests any approval regarding future ratemaking treatment. PacifiCorp notes, however, that upon retirement of the related assets and determination of actual removal costs, such costs will be trued-up for ratemaking purposes, at which time the regulatory accounts associated with these assets will be eliminated. For regulatory reporting purposes, the effects of SFAS 143 will be removed and there should be no rate change, now or in the future, associated with the application of the requested accounting treatment.

PacifiCorp also requests confirmation by the Commission that asset removal costs, in the form of negative net salvage, are currently accrued through annual depreciation expense which is recoverable in rates; that these costs are based on estimates of the final removal cost; and that such costs are trued-up for ratemaking purposes at the time the related assets are retired and the actual removal costs are determined. Staff does not believe that this confirmation should be in a formal Commission motion for accounting approval. However, Staff acknowledges that the company's characterization of the Commission's current ratemaking practices in regard to asset removal costs is correct.

PROPOSED COMMISSION MOTION:

Pacific Power & Light Company's accounting application in UM 1088 be approved, subject to the following condition: At any time PacifiCorp files a results of operations report or general rate change, for a period of five years, the company must provide Staff with all journal entries made under the requirements of SFAS 143 and any adjustments necessary to remove rate impacts of this accounting treatment.

Attachment

PacifiCorp UM 1088

ATTACHMENT A

SFAS 143 should not be used for ratemaking for the following reasons:

1. The primary focus of SFAS 143 is on financial statement presentation rather than cost recovery.

   - The FASB provided the following two reasons for issuing FAS 143: (1) Users of financial statements indicated that the diverse accounting practices that have developed for obligations associated with the retirement of tangible long-lived assets make it difficult to compare the financial position and results of operations of companies that have similar obligations but account for them differently; and (2) Obligations that meet the definition of a liability were not being recognized when those liabilities were incurred or the recognized liability was not consistently measured or presented.
   - The provisions of FAS 143 are primarily focused on determining the appropriate amount of the ARO liability to be reflected in the financial statements.
   - For ratemaking purposes the issue with asset removal cost is not balance sheet presentation. The ratemaking issue is how to properly estimate removal costs and how to recover them in a fair and equitable manner from the utility customers being served by the assets. This process of estimation and recovery is best accomplished through traditional utility depreciation procedures that are subject to regulatory review and oversight.

2. Adoption of SFAS 143 for ratemaking would effectively transfer the determination of the appropriate amount of asset removal cost from regulators to the FASB.

   - When removal costs are determined through a depreciation study, if the Commission disagrees with the company's estimates, the estimates are simply changed and the depreciation rates adjusted accordingly.
   - If the SFAS 143 estimates of removal cost are to be used for ratemaking, then the Commission must accept whatever amount is calculated by the company and determined by its external auditors to be in compliance with SFAS 143.

3. Under the provisions of SFAS 143, the recognition of removal cost in period expense over the life of the asset is "back-end loaded".

As a result of the application of present value techniques, SFAS 143 results in removal expense that is lower in the early years of asset life and greater in the final years.

....
....

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ARIZONA PUBLIC SERVICE COMPANY
Cash Working Capital Revisions
Twelve Months Ended December 31, 2002

Line	Description	Working Capital Requirement (Source)	Original /1/ Working Capital Requirement (Source)	Change
1	Cash Required for (Provided by) Operating Expenses	(31,452,572)	(20,969,724)	(10,482,848)
2	Other Revenue Lag Items	50,894,165	74,809,380	(23,915,215)
3	Special Deposits and Working Funds	258,266	258,266	0
4	Net Cash Working Capital Required for (Provided by) Operations	19,699,859	54,097,922 /1/	(34,398,063)

/1/ Consistent with Schedule B-5, page 1, of the Company's June 30, 2003 filing.

ISFSI Accounting

Line No.			$ in Millions
1.	ISFSI Reg. Asset (Line 12 Sch. B-1)		$ 46.1
2.	Def Tax on Reg. Asset (Line 4 Sch. B-1)		(18.2)
3.	Net Impact on Reg. Assets on Rate Base as of 12/31/02		27.9
4.	Proforma ISFSI Reg. Asset (Line 12 Sch. B-1)		4.3
5.	Def Tax on Proforma ISFSI (Line 4 Sch. B-1)		(1.7)
6.	Net Impact of Proforma of Reg. Asset on Rate Base		2.6
7.	Net Impact on Reg. Assets on Rate Base estimated as of 06/30/04		30.5
8.	Accrual of ISFSI Removal (offset to Line No. 1)	(46.1)	
9.	ISFSI Expenditures through 12/31/2002	2.2	
10.	Net Removal Accrual of ISFSI (Line 15 Sch. B-1)		(43.9)
11.	Def Tax on Removal Accrual (Line 4 Sch. B-1)		17.3
12.	Net Impact of Removal Accrual on Rate Base as of 12/31/02		(26.6)
13.	Net Impact of ISFSI on Rate Base		$ 3.9

ARIZONA PUBLIC SERVICE COMPANY
RCND Cost Rate Base
Adjustments to Schedule B-3 (Pro Forma Adjustments)
(Dollars in Thousands)

		(1)		(2)		(3)	
		SFR Schedule B-3 as Filed Test Year 12/31/2002		Palo Verde 2 Replace Steam Generator		Palo Verde 2 Retire Original Steam Generator	
Line No.	Description	Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
		(a)	(b)	(c)	(d)	(e)	(f)
1.	Gross Utility Plant in Service	$ 12,602,163	$ 12,561,199	$ 77,133	$ 76,999	$ (16,141)	$ (16,113)
2.	Less: Accumulated Depreciation & Amort.	4,950,671	4,921,971	195	195	(16,141)	(16,113)
3.	Net Utility Plant in Service	7,651,492	7,639,228	76,938	76,804	-	-
4.	Deductions:						
5.	Deferred Taxes	1,282,822	1,281,244	1,447	$ 1,444	-	$ -
6.	Other Deductions	322,463	321,341	-			
7.	Total Deductions	1,605,285	1,602,585	1,447	1,444	-	-
8.	Total Additions	698,121	690,812				
9.	Total Rate Base	$ 6,744,328	$ 6,727,455	$ 75,491	$ 75,360	$ -	$ -

ARIZONA PUBLIC SERVICE COMPANY
RCND Cost Rate Base
Adjustments to Schedule B-3 (Pro Forma Adjustments)
(Dollars in Thousands)

		(4) Remove Net Losses on Reacquired Debt		(5) Remove Capitalized Vehicle Leases		(6) Allowance for Working Capital Adjustment	
Line No.	Description	Total Co. (g)	ACC (h)	Total Co. (i)	ACC (j)	Total Co. (k)	ACC (l)
1.	Gross Utility Plant in Service	$ -	$ -	$ (19,553)	$ (19,253)	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.						
3.	Net Utility Plant in Service	-	-	(19,553)	(19,253)	-	-
4.	Deductions:						
5.	Deferred Taxes	(3,023)	(3,018)				
6.	Other Deductions						
7.	Total Deductions	(3,023)	(3,018)	-	-	-	-
8.	Total Additions	(7,652)	(7,639)			(34,398)	(33,482)
9.	Total Rate Base	$ (4,629)	$ (4,621)	$ (19,553)	$ (19,253)	$ (34,398)	$ (33,482)

ARIZONA PUBLIC SERVICE COMPANY
RCND Cost Rate Base
Adjustments to Schedule B-3 (Pro Forma Adjustments)
(Dollars in Thousands)

		(7) Change in Transmission Rate Base		(8) Total RCND Cost Adjustments		(9) Adjusted Schedule B-3 Test Year 12/31/2002	
Line No.	Description	Total Co. (m)	ACC (n)	Total Co. (o)	ACC (p)	Total Co. (q)	ACC (r)
1.	Gross Utility Plant in Service	$ 1,057	$ 837	$ 42,496	$ 42,470	$ 12,644,659	$ 12,603,669
2.	Less: Accumulated Depreciation & Amort.			(15,946)	(15,918)	4,934,725	4,906,053
3.	Net Utility Plant in Service	1,057	837	58,442	58,388	7,709,934	7,697,616
4.	Deductions:						
5.	Deferred Taxes			(1,576)	(1,574)	1,281,246	1,279,670
6.	Other Deductions			-	-	322,463	321,341
7.	Total Deductions	-	-	(1,576)	(1,574)	1,603,709	1,601,011
8.	Total Additions	4,209	3,332	(37,841)	(37,789)	660,280	653,023
9.	Total Rate Base	$ 5,266	$ 4,169	$ 22,177	$ 22,173	$ 6,766,505	$ 6,749,628

APS-11R

EXHIBIT

tabbies

APS-11R
admitted

REBUTTAL TESTIMONY OF PETER M. EWEN

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

Table of Contents

REBUTTAL TESTIMONY OF PETER M. EWEN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Peter M. Ewen. I am the Manager of the Forecasts Department for Arizona Public Service Company ("APS" or "Company"). In that role, I am responsible for preparing short-range and long-range forecasts of system peak demand and energy sales and projecting the optimal dispatch of available resources to minimize the cost of meeting those energy requirements. My business address is 400 North Fifth Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY SUBMIT WRITTEN TESTIMONY IN THIS RATE PROCEEDING?

A. No.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received Bachelors and Masters degrees in Economics from Arizona State University in 1985 and 1988, respectively. I have analyzed and forecasted electric energy and demand growth since 1988, first as a Staff member of the Arizona Corporation Commission ("Commission") and, since 1990, as an employee for APS. I have specifically analyzed the actual dispatch of our generating units in combination with market purchases to serve native load demand since 1998, and assumed full responsibility for making the optimal dispatch and associated fuel cost projections in 2000. I was formerly President of the Arizona Economic Round Table, a group of Arizona-based economists that specialize in studying the Arizona economy, and I am still a member of that organization. I also serve on the Joint Legislative Budget Committee's Finance Advisory Committee. This consists of a group of state economists who advise the Joint Legislative Budget Committee staff on the adequacy of the economic projections underlying their state revenue projections. I am also Chairman of the Arizona State University ("ASU") Dean's Board of Excellence, which is a group of local businessmen and women who support the College of Business Honors Program by mentoring students, funding scholarships, and providing insights to students and faculty on managing through topical business challenges.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am adopting the fuel and purchased power, customer annualization and weather normalization pro forma adjustment portions of APS witness Don Robinson's Direct Testimony as my own. I provide support for the need for the Power Supply Adjustment ("PSA") mechanism that is described in greater detail by Mr. Robinson. I respond to the recommendations of Staff witness Douglas Smith regarding the Palo Verde Nuclear Generating Station ("PVNGS") capacity factors and the associated cost used in the Company's fuel and purchased power pro forma adjustments. Next, I address an inappropriate adjustment to customer related expenses by Staff witness James Dittmer. I am recommending a modified fuel and purchased power pro forma adjustment to account for new information that has arisen subsequent to the filing of the Company's rate application and in this portion of my testimony will address Mr. Smith's recommendations regarding natural gas transportation costs.

I also respond to the assertion by Western Resource Advocates ("WRA") witness Dr. David Berry that wind energy would be a suitable purchased power and fuel hedge. Finally, I will answer specific questions raised by Commissioner Gleason in his letter in this docket dated October 29, 2003, including the net fuel savings attributable to each of the Pinnacle West Energy ("PWEC") plants and provide a discussion of off-system market sales embedded in the PWEC pro forma adjustment as compared to those shown in one of APS witness Ajit Bhatti's workpapers.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company's need for a PSA when one considers the continuing volatility of both purchased power and natural gas prices, especially in light of the Company's increasing dependence on both, could not be more obvious. Substantial volatility in the market prices for natural gas and power continue to persist, and this volatility can easily flow through to Company earnings in the absence of a PSA.

Staff's position, as offered by Mr. Smith of LaCapra and Associates, includes adjustments to the pro forma fuel and purchased power costs for PVNGS capacity factors and for natural gas fixed transportation costs. The adjustment for the PVNGS capacity factor is inappropriate and the fixed transportation costs require revision, but for reasons other than those suggested by Mr. Smith.

Dr. Berry's suggestion that wind energy would be a suitable hedge against volatile natural gas and power prices, ignores certain fundamental flaws with that recommendation, most of which stem from the intermittent nature of wind generation, which fluctuates daily, by season and from year to year. Most importantly, Dr. Berry's proposal will actually add risk to APS' generation portfolio instead of mitigating it.

I have identified four fuel expense items that total approximately $23 million that should be appropriately included in the APS cost-of-service as a result of new information since the Company originally filed its case. These adjustments are all the more important in the event that the Commission adopts the Staff recommendation and does not authorize a PSA mechanism.

Q. WHAT PORTIONS OF MR. ROBINSON'S DIRECT TESTIMONY ARE YOU ADOPTING?

A. The specific portions of Mr. Robinsons' Direct Testimony, Attachments, Workpapers and Standard Filing Requirement ("SFR") Schedules that I am adopting are detailed on Schedule DGR-1RB of Mr. Robinson's Rebuttal Testimony.

II. POWER SUPPLY ADJUSTMENT MECHANISM

Q. HAVE YOU REVIEWED MR. SMITH'S TESTIMONY REGARDING THE COMPANY'S REQUEST FOR A PSA MECHANISM?

A. Yes, I have.

Q. DID MR. SMITH RECOMMEND A PSA?

A. No. But he did make several recommendations should the Commission elect to grant APS a PSA despite his proposed rejection of the Company's request.

Q. DO YOU HAVE ANY COMMENTS ON HIS RECOMMENDATIONS?

A. Yes. Mr. Smith appropriately recognizes an adjustment mechanism should alleviate the risk from volatile natural gas and power price fluctuations and that there is a strong inter-relationship between the natural gas and power markets and the resource options available to the Company. But he uses little more than conjecture to support a wide "no adjustment" deadband that would require the Company to bear 100% of the risk of varying fuel costs up to $20 million in either direction. The Company strongly disagrees with that recommendation, as it likely would result in chronic over- or under-recoveries of prudent fuel and purchased power costs.

Q. DO YOU WISH TO COMMENT ON ANY OTHER CONCLUSIONS REACHED BY MR. SMITH?

A. Yes. Mr. Smith also suggests that the implementation of a fuel adjustment mechanism would provide the Company with a natural over-earnings potential based on an incorrect assumption that APS fixed costs are recovered over progressively more KWh sales. As I discuss below, this is simply wrong and fails to recognize the reality of how the Company's costs increase year-by-year. In fact, over the last five years, the Company's "fixed costs," as Mr. Smith refers to them, have increased at virtually the same rate as sales growth experienced over the same time period.

Q. DOES VOLATILITY IN THE NATURAL GAS AND POWER MARKETS AFFECT COMPANY EARNINGS?

A. Yes, it clearly does. Even minor price moves in the gas and power markets can have significant impacts on Company earnings. In order to serve retail customer energy demand, the Company expects to burn approximately 34 million MMBTU of natural gas in 2004 and almost 50 million MMBTU in 2005. Additionally, the Company anticipates purchasing 2,600 GWH of electricity from the market in 2004 and 1,800 GWH in 2005 to meet retail load. These volumes are up substantially from only a relatively short time ago, as incremental load growth must be served with increased gas generation or power purchases from the wholesale market. Since the Company's last settlement in 1999, the amount of natural gas being burned in 2004 has increased by 127% and the amount of purchased power has increased by 46%.

An upward move of $1/MMBTU in natural gas prices (with a corresponding increase in power prices of $8/MWh that maintains the average "spark spread" at roughly current levels) translates into an additional cost to serve retail customers of about $55 million in 2004 and almost $65 million in 2005. On an after-tax earnings basis, these amounts convert to $33 million in 2004 and $39 million in

2005. Assuming an equity base of $2.6 billion, the Company's earned ROE would decline by 1.3 percentage points in 2004 and 1.5 percentage points in 2005.

Q. WHAT DO YOU MEAN BY THE TERM "SPARK SPREAD" AND WHY IS IT IMPORTANT?

A. The spark spread (also referred to as the implied market heat rate) is the ratio of power prices to natural gas prices and represents the break-even heat rate for the marginal gas-fired generating unit in the market. Changes in the spark spread will affect the Company's decision on whether to burn fuel to generate power or buy power on the open market. As an example, if the market price for power is $40/MWh and natural gas price is $5/MMBTU, the resulting spark spread is 8 MMBTU/MWh or 8,000 BTU/KWh. If the spark spread were the only factor considered in dispatching power plants, any gas-fired generating unit operating at less than an 8,000 heat rate would be running to serve load or make sales and any unit with a heat rate greater than 8,000 would be idle. That is, it would be more economic to purchase electricity from the market at $40/MWh than it would be to buy natural gas at $5/MMBTU and burn it in a power plant where the incremental heat rate exceeds 8,000 BTU/KWh and consequently the average production cost exceeds $40/MWh.

The assumption of a constant spark spread in the example I cited above makes the calculation of earnings impacts much more straightforward because one can ignore any changes in the mix of supply sources. When spark spreads widen (e.g., the price for power increases more than the price for natural gas), all else being equal, the economic choice will be to shift away from purchases from the market and toward more Company-owned gas generation. Likewise, when these spreads narrow, the economic choice will be toward more power purchases. In these latter situations, the impact of rising prices may be mitigated by more economic fuel use choices.

As an example, if market prices for power increased by \$10/MWh instead of \$8/MWh in response to a \$1/MMBTU increase in the gas price, basic accounting would suggest an increase in costs of \$60 million in 2004 instead of \$55 million. Because the market heat rate has increased, however, some higher heat rate gas generation that previously was uneconomic may now be able to displace market purchases and bring the increase in costs down below \$60 million, but still above \$55 million.

Q. ARE THE EARNINGS IMPACTS YOU HAVE DESCRIBED ABOVE SYMMETRIC WITH PRICE DECREASES INSTEAD OF INCREASES?

A. Yes, assuming constant spark spreads, these same price changes downward would serve to reduce the Company's fuel and purchased power expenses by the same amount as the increases highlighted above. If the spark spreads were to change, then the re-optimization of the resource mix would have to be taken into account as well. In any event, the PSA mechanism proposed by Mr. Robinson flows through cost increases and cost reductions symmetrically. It is only fair that customers should get the timely benefit of declining costs if they are to cover the timely cost of rising fuel and power prices.

Q. HOW DO THE MARKET PRICE CHANGES YOU HAVE USED IN THIS ILLUSTRATIVE EXAMPLE COMPARE WITH RECENT CHANGES IN GAS AND POWER PRICES?

A. The recent history of gas and power price movements shows substantial volatility and shows that the Company's earnings can be drastically affected without a fuel adjustment mechanism. In fact, prices for both gas and power increased from 2002 to 2003 by about double the amounts used in the example above. Attachment PME-1RB provides a summary of historical daily spot electric and natural gas prices over the last six years. Natural gas prices are provided for three major delivery points – Henry Hub in Louisiana, the San Juan Basin in northern New Mexico, and at the Southern California ("SoCal") border. Henry Hub is an important market in the U.S. and is the basis against which most other natural gas markets trade. San Juan and the SoCal border are markets that are more specific to the Company.

The historical data show that natural gas prices in the San Juan basin have averaged \$3.07/MMBTU since 1998 and at the SoCal border have averaged \$4.48/MMBTU. On-peak power prices at Palo Verde have averaged \$61.18/MWh over the same time period. What is more striking, though, is the range of prices that have been seen over this time period, from a low San Juan gas price of \$1.00/MMBTU to a high of \$10.16/MMBTU. The price at the SoCal border shows an even more extreme result with a low price of \$1.40/MMBTU somewhat close to that of San Juan, but a high price of \$59.42/MMBTU, which is much higher than the highest price seen at San Juan. The standard deviation for gas prices over this time period, a statistical measure of volatility, falls at \$1.49/MMBTU for San Juan and \$4.55/MMBTU for the SoCal border. These standard deviation results mean that San Juan daily prices have differed from the average price by a minimum of \$1.49/MMBTU about one-third of the time. Attachment PME-2RB shows graphically the trend in daily San Juan basin spot prices since 1998.

Power prices also have exhibited a great deal of volatility over this time period. The lowest price for on-peak power as reported by Dow Jones since 1998 is \$8.56/MWh and the highest price is \$537.02/MWh. The standard deviation of power prices is \$68.82/MWh. Attachment PME-3RB shows graphically the trend in daily Palo Verde spot prices since 1998, although the scale has been limited to

$150/MWh so the price movements in years not affected by the California energy crisis can be seen more clearly.

Q. DOES THE IMPACT OF THE CALIFORNIA ENERGY CRISIS AFFECT THESE VOLATILITY RESULTS?

A. Yes, but removing these years does not change the conclusion that power and gas prices have been volatile. Attachment PME-1RB provides similar statistics to those described above, but for the time period from July 2001 forward. Mid-2001 is about the time that the Federal Energy Regulatory Commission ("FERC") imposed price caps on power markets in the West and, as a consequence, prices became less extreme. Since July 2001, the standard deviation of natural gas prices at San Juan is $1.24/MMBTU and $1.27/MMBTU at the SoCal border. These levels equate to about 35% of the average price observed over the same time period, meaning that daily gas prices have been at least 35% different from the average one-third of the time. On-peak power prices show almost exactly the same relationship.

In addition to these simple measures of volatility, a quick inspection of Attachment PME-1RB shows that the recent trend in natural gas prices has been an increasing one and a rapidly increasing one at that. Natural gas prices at all three locations shown on Attachment PME-1RB increased by about $2/MMBTU between 2002 and 2003, or more than 60%. This increase began to materialize in very late 2002 and stabilized only in the spring of 2003. Another rapid increase in prices has been seen here in early 2004.

The trend in power prices is correlated to the move in gas prices, although slightly lower. The increase in power prices of almost $17/MWh from 2002 to 2003 translates into a 52% increase in the annual price. These results are roughly double the price changes I described in my illustrative example earlier in my testimony.

Corresponding to these power and gas price movements are changes in the daily spark spread, which are shown on Attachment PME-4RB. (As was done with the graph of power prices, the scale has been limited so that recent trends are more clearly visible.) As expected, when gas prices rise at a faster rate than power prices, the spark spread declines, and this is indeed what has been happening since mid-2001. The daily spot spark spread between Palo Verde on-peak power and San Juan natural gas declined by almost 13% from 2002 to 2003. As a consequence, economic decisions would have dictated relying on purchased power more than natural gas generation in 2003 than in 2002. Because the spark spread is as unpredictable as natural gas and power prices, the supply choices between gas-fired generation and purchased power must be carefully balanced. This unpredictable nature of spark spreads is the primary reason the Company is requesting a PSA that includes both fuel and purchased power.

Q. IS THIS VOLATILITY IN THE MARKETS FOR NATURAL GAS AND POWER CONFINED TO THE DAILY SPOT MARKETS?

A. No. Over the last 5 years, forward price curves for both natural gas and power have also seen substantial volatility. Attachment PME-5RB provides a summary of daily market quotations for natural gas at Henry Hub and San Juan and on-peak power at Palo Verde to be delivered over the calendar years of 2002 through 2005. From this summary, it can be seen that natural gas prices at the actively traded Henry Hub basin have ranged from a low of $2.44/MMBTU for delivery over the full year of 2002 to a high of $5.68/MMBTU for delivery over the full year of 2004. Prices for on-peak power on average at Palo Verde have ranged from a low of $18.86/MWh for delivery over the full year of 2004 to a high of $180.89/MWh for delivery over the full year of 2002. These price statistics reflect the daily market quotes compiled over the three years prior to commencement of delivery. For example, the average price of $4.19/MMBTU for Henry Hub in 2004 is the average of daily market quotes for natural gas to be delivered at Henry Hub for the 12 months of 2004 compiled between January 1, 2001 and December 31, 2003. (The data for 2002 are an exception in that a full three years was not available, and the data for 2005 were compiled over the same time period as the data for 2004.)

Q. IS THE VOLATILITY IN THE FORWARD MARKETS SIMILAR TO THE SPOT MARKET VOLATILITY DESCRIBED ABOVE?

A. As a percentage of the average quoted price, the standard deviation of the historical market quotes tends to be lower than the standard deviation of daily spot prices, but the timing and magnitude of price movements appears to be just as sporadic. The standard deviation of forward natural gas prices at Henry Hub has been as high as 24% on an average gas price of $3.39/MMBTU for 2002 delivery and as low as 13% on an average price of $4.05/MMBTU for delivery in 2005. For power, the comparable ratios show a high of as much as 50% on an average power price of $74.66/MWh for delivery in 2002 and a low of 14% on an average power price of $42.30/MWh for delivery in 2005.

Q. DID THE CALIFORNIA ENERGY CRISIS AFFECT THE VOLATILITY IN FORWARD MARKETS ALSO?

A. Yes, it greatly increased the volatility, but volatility in the forward markets has not gone away. Volatility is highest for the gas and power contracts to be delivered in 2002 primarily because many of the market quotes for that year were received during the volatile 2000-2001 time period. However, forward natural gas price volatility for years that do not include quotes from 2000 or 2001, such as 2004 and 2005, is still about half of the 2002 volatility. Relative to 2002, the volatility in forward power prices has declined more than the volatility in natural gas prices, but only because the volatility in power was more severe. Power price volatility is currently comparable to the volatility seen in the natural gas markets.

This volatility is shown graphically in Attachments PME-6RB through PME-9RB. Each graph provides the daily market quotations for a given calendar year for natural gas at Henry Hub and on-peak power at Palo Verde. Even though the absolute measures of volatility have abated somewhat, volatility is readily apparent in each graph. Attachment PME-8RB, for example, portrays the changes in forward prices for calendar year 2004 delivery from January 2001 through December 2003. These quotes are characterized by frequent and sudden changes of somewhat surprising magnitude. Price movements of almost $1 or more in natural gas can be seen in January through March of 2002, December 2002 through February 2003, March through June 2003 and as recent as November and December 2003. Power prices have reacted similarly. Volatility may be lower now than it was during the California energy crisis, but it is still present and can be dramatic.

Q. DOES A PSA MECHANISM WITH A DEADBAND SIMILAR TO THE ONE PROPOSED BY MR. SMITH EFFECTIVELY DEAL WITH THIS VOLATILITY?

A. No. Although it is better than no mechanism at all, the size of the deadband recommended by Mr. Smith is far too large to address this volatility. As I discussed above, gas and power prices have been and are expected to remain quite volatile, thereby having a significant impact on the Company's earnings. It should be clear from the above discussion that Mr. Smith's proposed deadband limits of plus or minus $20 million can be reached rather easily. This suggests that the Company is likely to experience sizable fluctuations in its earnings from one year to the next and, at the extreme, could see a swing of up to $24 million from changing fuel prices alone. This would be the case if we were to hit <u>or exceed</u> the cap in one direction in one year and price movements caused us to hit or exceed the cap in the opposite direction the following year. The ROE impact of such a change would be 0.9 percentage points. It should be evident that such a wide deadband around volatile fuel costs, when placed on top of all of the other factors that create uncertainty in Company earnings, simply adds to the riskiness of the Company's earnings profile and increases the level of return required by investors to hold the Company's stock. APS witness Donald Brandt discusses in more detail the ROE impacts and financial community reactions.

Q. WHAT OTHER FACTORS CREATE UNCERTAINTY IN COMPANY EARNINGS?

A. Many other factors beyond the Company's control must be managed on an on-going basis. Briefly, these factors include abnormally hot or cold weather, changes in economic growth, general inflation and specific cost increases for needed products and materials, vendor performance, labor cost increases, interest rates, mechanical performance, natural disasters, and government rules and regulations. Except for weather, these items generally are less volatile than fuel prices and constitute a smaller share of the Company's total cost structure than fuel costs. Taken together, though, they represent a broad source of uncertainty in future earnings.

Q. WHY DOES MR. SMITH PROPOSE SUCH A WIDE DEADBAND?

A. It appears that Mr. Smith's rationale for such a wide deadband is two-fold. First, he indicates that because of the rather rapid rate of growth in the Company's service area, the Company is more likely to overearn as fixed costs are spread over more and more sales of electricity. Second, Mr. Smith states that the Company should have an incentive to manage its overall fuel and purchased power costs and if it bears the risk of large cost fluctuations, it will manage these costs more aggressively. With only some minor reflection and a cursory historical analysis, however, it becomes clear that neither point is persuasive, let alone compelling.

Q. WHY DO YOU FIND THESE POINTS UNPERSUASIVE?

A. Attachment PME-10RB provides an historical perspective on the Company's "fixed costs" and how they have changed over the last five years. In addition, I have displayed the Company's sales growth and converted the fixed costs to an average unit cost for each year. The trend that emerges shows very clearly that "fixed costs" are fixed in name only. Since 1999, with the exception of the amortization of the Company's regulatory assets, which declined every year, the Company's fixed costs have increased by $146 million, or 15.8%. When compared to sales growth of 16.6% over the corresponding time period, average fixed costs have declined by about half of one percent. The cumulative net gain from this change is about $4 million in earnings, or less than $1 million per year.

This result makes perfect sense when one considers all of the Company's efforts each year to enhance the system in order to meet the continued high rate of growth in customers and total energy demand. The Company adds more plant and equipment each year to upgrade and improve both the generation and delivery systems. Cost escalation is a factor in both labor and materials costs and, with a growing system, maintenance expenditures increase every year as well. In short, the Company is at very little risk of overearning on the basis of rapid sales growth serving to lower average unit costs.

Q. WHAT IS WRONG WITH MR. SMITH'S CONCERN REGARDING THE NEED FOR THE COMPANY TO HAVE AN INCENTIVE TO MANAGE ITS FUEL AND PURCHASED POWER COSTS?

A. First, the Company has had and will continue to have a strong incentive to keep all costs down, not just fuel and purchased power costs. This incentive inherently exists in the Company's desire to minimize rate impacts on customers. With the adoption of a PSA such as that proposed by Mr. Robinson, the Company would still retain its goal of maintaining as much price stability for its customers as possible. Moreover, the Company's proposal, as explained in more detail by Mr. Robinson, to implement a 90% customers/10% Company sharing of costs and benefits provides more than adequate incentive for the Company to manage fuel and purchased power costs.

Q. MR. SMITH RECOMMENDS THAT IF THE COMMISSION GRANTS APS A PSA, THE COMPANY SHOULD DEVELOP A FORWARD HEDGE STRATEGY FOR FUEL AND PURCHASED POWER EXPENSES. DOES THE COMPANY AGREE?

A. Yes. As explained by Mr. Robinson, given the volatility of both natural gas and power prices in today's market and the Company's increasing dependence on natural gas and purchased power, APS strongly believes that a hedge strategy is and has been important. However, although hedging helps mitigate price uncertainty, hedges cost money, and the Company would expect such costs to be included in each annual calculation of fuel and purchased power costs. Because forward hedges can protect both the customer and APS from financial risk of price uncertainty without sacrificing reliability of supply, the costs of such hedges would be included in the PSA as either a fuel or purchased power cost, depending upon the nature of the hedge.

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S CURRENT HEDGING PROGRAM.

A. Over the past several years, the Company has successfully executed a hedging program that protects the Company and its customers from the more dramatic price swings in the commodity markets. Our past experience with this hedging program suggests that the Company will likely be able to maintain its fuel and purchased power costs within a reasonable range, but that no hedge is perfect because significant price deviations have occurred and will continue to occur.

This hedging program typically involves purchasing natural gas and power contracts at a fixed price one or more years ahead of the time of actual delivery. The extent to which the forecasted natural gas and power needs are contracted ahead of time will largely determine the level of certainty of future fuel and purchased power costs, but the success of the hedging program is limited by the availability of distinct product types in the market, the forward price prevailing in the market when the Company initiates its hedging program, the accuracy of the demand projections, the performance of the Company's generating units, and credit and liquidity conditions in the market. These factors, among others, will ensure that no hedge program will entirely eliminate market risk and exposure.

The Company primarily enters into NYMEX gas futures contracts, but also uses other types of contracts such as "swaps" of various types (futures, index, and basis) and options. Even though most of these positions are initially put on at Henry Hub, a location at which the Company would not naturally take delivery, we are able to achieve increased price stability for future gas burns up to the amounts we hedge (or contract for) by relying on the interrelationships among the various major producing basins and the likelihood that prices in all basins will move together.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE ABOVE?

A. Certainly. To provide a simple example, if the Company forecasted that the demand for natural gas at our plants was going to be 20 million MMBTU for a year three years in the future and that most of our supply would have to come from the San Juan and Permian basins, we could still hedge out a portion of risk by purchasing up to 20 million MMBTU of futures contracts at Henry Hub. Once these contracts are purchased and the rights to the gas are owned by the Company, the Company has effectively mitigated the risk of major price moves in the natural gas market. To carry out the example, suppose that the futures were purchased at an average price of $4/MMBTU at a total cost of $80 million. Furthermore, suppose that over the succeeding two years, natural gas prices increased by $2/MMBTU and that this was a general price rise experienced by all major basins. The result is that the Company's hedges (the futures contracts) have risen in value by $40 million (the $2 price increase on the 20 million MMBTU under contract), but this increase in value is just enough to pay for the additional cost of gas that must be procured physically in the San Juan and Permian basins – the $2 price increase on the forecasted 20 million MMBTU to be burned. Attachment PME-11RB provides an overview of this situation. I would like to reiterate, though, that this is an over simplified example. In actual practice, it is virtually impossible to hedge the Company's fuel and purchased power risk completely because of the factors I mentioned before.

Q. WHY DOES THE COMPANY HEDGE AT HENRY HUB?

A. The Company currently hedges at Henry Hub instead of at the basins relied upon for actual physical delivery of natural gas because Henry Hub provides the most liquid market for forward purchases two or three years ahead. Henry Hub has many buyers and sellers, transacts large quantities, and has the best price transparency – meaning the ability to execute at quoted prices out in the future. Because of these characteristics, the Company can more effectively purchase the quantities it needs with the lowest risk of affecting the market. In practice, the Company considers many risks in implementing the hedging program, including basis risk among the various producing basins, uncertainty surrounding the forecasted volumes, and the mismatch between the highly structured contracts available in the forward market and the required shaping of daily natural gas burns. The first priority of the Company's hedging program, however, is to minimize the largest source of risk, i.e., an overall market price move.

III. PVNGS CAPACITY FACTOR

Q. DO YOU AGREE WITH MR. SMITH'S ASSESSMENT OF THE NUCLEAR UNIT CAPACITY FACTORS?

A. No. Mr. Smith argues at pages 33-34 of his testimony that the Company's assumption for the capacity factors on the nuclear units is too low. In doing so, he overstates both the reasonable availability level of PVNGS and the associated costs that can be avoided by higher output from PVNGS, and consequently reduces the Company's fuel and purchased power costs by $5 million. Mr. Smith's recommendation inappropriately penalizes the Company for exceptionally strong performance at its nuclear plant over the 2000-2002 time period, particularly in 2002 when the Company achieved a uniquely high capacity factor of 94.4%. Additionally, he does so with an avoided purchase price that is 25% too high.

The capacity factor results included in the Company's pro forma adjustments take into account normal refueling outage times as well as a normalized level of unplanned outages and, therefore, reflect the appropriate capacity factors on a going forward basis. The 90.6% capacity factors used by the Company in its filing are still above the three-year average of 88.6% for the industry and reflect a better than average unplanned outage rate. Contrary to Mr. Smith's characterization, the Company did not simply make an assumption about what capacity factors to use for PVNGS. Rather, the capacity factors underlying the pro forma adjustments result from a calculation using the output of the simulation model, which necessarily relies on driving assumptions that are "inputs" to the model, including planned and forced outage days. These assumptions were normalized to appropriate levels.

Q. HOW DID YOU NORMALIZE PLANNED OUTAGE DAYS?

A. To normalize planned outage days, I began with the Company's 2003 budgeted planned maintenance schedule for the nuclear units. I then adjusted that schedule to arrive at the same number of planned outage megawatt-days as the plant experienced on average in the three prior years. Although I did not put in outages to reflect each unit's unique historical outage days, as a practical matter, that decision did not affect the results because the overall target of "megawatt-days on outage" was achieved. Attachment PME-12RB shows that the pro forma included 25,360 MW-days for planned outages, which is slightly less than the 25,467 MW-day average for the previous three years. The difference is about one-third of a day at one unit, and slightly understates our actual fuel expense.

Q. HOW DID YOU NORMALIZE UNPLANNED OUTAGE TIME?

A. The forced outage rates used in the simulation model reflect an average unplanned outage time of 2.5%. These rates are the same as the rates used in our recurring planning assumptions and better reflect the performance levels achievable over time than the rates used by Mr. Smith. At 2.5%, the unplanned outage time at PVNGS is still better than the industry average of over 3.0%. The time period captured by Mr. Smith in his adjustment reflects forced outage time that was somewhat less than 2.5%, but this level of performance is also less repeatable over time.

Q. IF A DIFFERENT THREE-YEAR PERIOD WERE USED TO NORMALIZE THE PVNGS CAPACITY FACTORS, WOULD YOU ARRIVE AT DIFFERENT CONCLUSIONS?

A. Yes. For example, we now have results for 2003, which would allow us to use the 2001-2003 period as an alternate, and more current, measure of average capacity factor. Those results show an average capacity factor of 90%, which is lower than the 90.6% used in the original pro forma and is far lower than the 91.8%

calculated by Mr. Smith, but still includes the strong results from 2002 of 94.4%. These results are shown in Attachment PME-13RB. In fact, 2002 represents the single best year ever for PVNGS' annual capacity factor and will therefore raise any three-year average that includes that year. The three year capacity factor for 1999-2001 shown in Attachment PME-13RB, while still high, averages only 91.2%, which is about 57 GWh less than that proposed by Mr. Smith.

Q. WHAT IS THE RIGHT NUMBER TO USE FOR PVNGS'S CAPACITY FACTOR?

A. The most reasonable number to use for PVNGS' production level is the 90.6% capacity factor as originally filed in the Company's case. This level incorporates normal refueling outage times and unplanned outage times that are achievable and better than the industry average. In fact, these normalized levels ignore the effects of the steam generator replacement outages that will occur twice more in the next four years. By raising the capacity factor to 91.8%, Mr. Smith overstates the largest reasonable adjustment by at least 57 GWh or 105%. At $50/MWh for replacement energy, which is Mr. Smith's assumption, he overstates the adjustment by at least $2.9 million.

Q. DID MR. SMITH USE THE APPROPRIATE AVOIDED COST IN PREPARING HIS RECOMMENDED ADJUSTMENT?

A. No. In addition to overstating the appropriate PVNGS capacity factor, Mr. Smith uses a generous price of $50/MWh to reflect the costs avoided when nuclear production is increased, so he overstates the amount saved by $1.1 million. When the Company adjusted the simulation to increase the capacity factor of the nuclear units by one percent, we found that only $3.8 million in savings would be achieved, at an average cost of $39.69/MWh. This result is more reasonable considering the amount of gas-fired generation that could be displaced along with some market purchases. In the simulation, gas-fired generation declined by 56

GWh at an average cost savings of $42.70/MWh, while avoided purchases amounted to 26 GWh at an average cost savings of $35.80/MWh, reflecting the displacement of a mix of on-peak and off-peak purchases. The difference between Mr. Smith's assumed $50/MWh and the calculated average cost of $39.69/MWh times Mr. Smith's calculated 111 GWh increase in nuclear production yields an overstatement of $1.1 million.

IV. REBUTTAL TO MR. DITTMER

Q. DO YOU AGREE WITH MR. DITTMER'S ADJUSTMENT TO CUSTOMER-RELATED O&M EXPENSES?

A. No. Mr. Dittmer recommends removing the Company's adjustment in the customer annualization pro forma for additional O&M expenses that increase with the number of customers. He argues that he sees no correlation between the historical costs in the FERC accounts represented in the adjustment and corresponding customer growth. That argument, however, is simply wrong.

It only makes sense that certain non-labor costs will increase as the number of customers taking service and being billed each month increase. Attachment PME-14RB shows the specific FERC accounts that were included in the Company's customer annualization pro forma adjustment in the original filing. These expenses include such items as meter reading expenses, customer records and collection expenses, and customer assistance expenses. Although it may be difficult to show that such expenses vary perfectly with customer changes from year to year, to suggest that they do not vary at all is a mistake. One is left with the choice of making no adjustment, which would be incorrect, or making an attempt at a reasonable adjustment based on the average cost per customer in the test year. It has been the past practice of this Commission to include this adjustment.

V. ADDITIONAL PRO FORMA ADJUSTMENTS

Q. WHAT FUEL EXPENSE ITEMS ARE YOU PROPOSING TO INCLUDE AT THIS TIME?

A. They are:

1. A reversal of the 10% downward adjustment to forward natural gas prices in the Company's original filing to account for the lack of movement in forward spark spreads.

2. An updating of the demand charge associated with the Salt River Project ("SRP") Territorial and Contingent purchase agreement to reflect year-end 2004 levels.

3. Lower costs related to a re-assessment, with several months of practical experience under the new contract demand ("CD") framework, of required incremental gas transportation purchases.

4. The impact of a fuel excise tax being assessed by the Navajo Nation on the Company's coal supplier at Four Corners.

Attachment PME-15RB summarizes each of these adjustments.

Q. WHY ARE YOU PROPOSING THESE VARIOUS ADJUSTMENTS NOW?

A. For a couple of reasons. First, on most of these items, since the Company filed its rate case application, known and measurable changes to test year costs have come to light. Those changes should be taken into account. Second, the onerous Staff recommendation, including a proposed rejection of the Company's request for a PSA mechanism, significantly increases the risk to the Company of not getting full recovery of even these already known and measurable changes reflected in the base fuel rate, let alone future increases. As I have described above, the Company's fuel and purchased power costs are likely to exhibit considerable volatility in the coming years. If the Company felt it had assurance that the Commission would authorize a PSA mechanism allowing the Company to recover these volatile costs on a reasonably timely basis without the need for a long drawn-out general rate case proceeding, then the financial costs to APS of not including all relevant fuel and purchased power costs in base rates might be mitigated. Staff's recommendation against a PSA mechanism suggests, however, that the Company may be at very high risk of going for some time under-recovering these known and measurable costs.

Q. ARE THERE ANY OTHER REASONS FOR ADJUSTING THE NATURAL GAS PRICES NOW FROM THE LEVELS THAT WERE INCLUDED IN THE COMPANY'S RATE CASE FILING?

A. Yes, there are. Two conditions have changed since the Company's filing was prepared in the spring of 2003. First, because the Company expected natural gas prices to trend lower over time when it filed its application, we elected to give customers the benefit of that expectation. Since the filing, however, the forward spark spread market has remained lower than the Company originally anticipated when it filed the rate case (*i.e.*, gas prices have continued to increase while power prices have remained depressed), and the Company is less confident of any near-term decline in gas prices as presumed in the Company's filing. Second, the Staff has recommended against the implementation of a PSA, in which case the risk of being wrong on the future direction of the market spark spreads is too high for the Company to bear.

Q. WHY IS THE FORWARD SPARK SPREAD AT ISSUE HERE?

A. The low spark spreads embedded in the forward markets at the time of the Company's filing were resulting in higher generating costs to serve retail customer energy demand and lower margins from off-system sales. These low spark spreads were created by generally increasing gas prices without a corresponding increase in power prices. The movement in gas and power prices was particularly pronounced starting in late 2002 through the end of April 2003. Attachment PME-16RB shows the historical market price quotations for natural gas at Henry Hub and for around-the-clock power at PVNGS for the delivery period beginning May

1, 2003 and ending April 30, 2004. This delivery period is consistent with the forward price curves used in the Company's fuel and purchased power pro forma.

The Company was reluctant to base its original rate request on spark spreads that could be unsustainable over a long time horizon. Specifically, the Company believed that the forward sparks at the end of April 2003 were more likely to be close to an absolute bottom such that a higher probability existed of having wider spark spreads in the future than lower. The Company believed it would be more appropriate to have a base fuel rate that reflected this event (which, at the time was considered to be more likely than no change at all) with a resulting greater chance of exhibiting both positive and negative fuel adjustment charges going forward than to set the base rate too high and thereafter use the PSA to adjust downward.

Q. DOES THE COMPANY STILL BELIEVE THAT THE MARKET SPARK SPREADS WILL GRADUALLY WIDEN OVER THE NEXT COUPLE OF YEARS?

A. What we know is that there has been no widening of the spark spread since the Company filed its case nine months ago. In fact, the average annual spark spread for the twelve calendar months February 2004 through January 2005 delivery quoted over the last week of January 2004 is 2.5% lower than the average annual spark spread quoted over the last full week of April 2003. The last week of April 2003 coincides with when the Company completed its evaluation of Track B bids, and the market quotes from that time period (prior to the 10% adjustment to natural gas prices) were the basis for the Company's fuel and purchased power pro forma adjustments. Attachments PME-8RB and PME-9RB both confirm that forward markets for 2004 and 2005 delivery of gas have increased faster than those for power, meaning that the spark spread has not rebounded.

Q. WOULD THE AVAILABILITY OF A PSA ELIMINATE THE NEED TO HAVE AN ACCURATE FORECAST OF FORWARD POWER AND NATURAL GAS PRICES IN THIS RATE CASE?

A. No. With the incentive the Company has proposed, forecasts will continue to be important. Without a fuel adjustor and in light of the lack of movement in the forward spark spread, the Company faces too much risk in potential fuel costs to not request full recovery of such costs at the unadjusted forward prices from April 24, 2003. As a result, I have removed the 10% discount to natural gas prices that was included in the Company's original filing and re-estimated our fuel and purchased power costs.

Q. WHAT IS THE RESULT OF THIS ADJUSTMENT?

A. The Company incurs a net increase in system costs of $27.3 million – about $11.2 million related to serving retail customer demand and another $16.1 million in reduced off-system sales margin. Of the net change in retail energy supply costs, the Company experiences an increase of $14.6 million related to higher gas fuel costs (partly offset by a shift to more economic purchased power) and a decrease of $3.4 million related to lower gas transportation capacity requirements. At these lower spark spreads, the Company's daily demand for natural gas is lower than in the previous pro forma adjustment and, therefore, the amount of pipeline capacity that must be reserved is lower. If spark spreads increase, however, the use of the Company's gas-fired generation will increase and the cost of transporting the natural gas for this generation increases as well.

Q. WHAT IS THE ADJUSTMENT FOR THE SALT RIVER PROJECT PURCHASE CONTRACT DEMAND CHARGE?

A. The adjustment being proposed by the Company is similar to the pro forma adjustment in the original filing, but reflects updated information. The original pro forma included a cost that annualized the 2003 year-end expense related to the SRP demand charge. Now that 2003 has passed, the 2004 year-end costs related to the demand charge can be estimated quite closely at a $2.3 million increase over

2003's level, going from $1.3 million per month to $1.5 million per month. These costs follow a very predictable formula in a contract approved by this Commission and are therefore known and measurable costs. An additional benefit related to this adjustment is that the expenses will be more contemporaneous with when new rates are expected to go into effect.

Q. WHAT IS THE NAVAJO NATION FUEL EXCISE TAX ADJUSTMENT?

A. The Navajo Nation assesses an off-road fuel excise tax on a company contracted to do work for BHP Billiton ("BHP"), the coal supplier to the Four Corners Power Plant. APS and the other owners of Four Corners reached agreement with BHP on a new long-term contract in August 2003. At that time, BHP began passing through these costs to the Company. While most of the terms of the new contract had been recognized in the Company's original filing, this new cost element did not become apparent until the first invoices under the new contract arrived in September 2003. For the total plant, the increase amounts to about $790,000 annually, or about $0.007/MMBTU or $0.124/ton. The company's share of this annual increase is $280,000. Attachment PME-15RB shows the calculation of these amounts.

Q. WHAT ADJUSTMENTS ARE YOU PROPOSING FOR NATURAL GAS TRANSPORTATION COSTS?

A. Several changes have occurred since the Company's filing in June 2003. First, having now had a few months of practical experience under the new CD transportation structure imposed by FERC, we have updated our assessment of how much of our allocated capacity can be relied upon on a firm basis. Second, the availability of El Paso's Line 2000 Power Up capacity is ahead of the schedule we anticipated several months ago, providing more firm transport capacity in the near term than originally was contemplated. Third, the initial simulation did not appropriately account for the effect of incremental gas transportation purchases on the economic dispatch of the system. The net effect of all of these adjustments is a reduction in expense of $6.0 million. This adjustment should replace Mr. Smith's recommended adjustment of $4.6 million (at page 24 of his testimony.)

Q. HOW HAVE YOU UPDATED THE FIRM PIPELINE CAPACITY AMOUNT?

A. As described in Mr. Smith's testimony, in moving to the new CD regime ordered by FERC last year, the Company has been allocated several different types of capacity on the El Paso system. The total allocation of capacity amounts to an average of 221,847 MMBTU/day and is shaped on a seasonal basis. On average, 181,082 MMBTU/day is firm capacity that can be relied on for deliveries into the Phoenix area. The remaining capacity is El Paso Northern mainline system delivery point capacity (*i.e.*, lower priority and therefore not likely to flow to the Phoenix area). Attachment PME-17RB shows the allocated capacity by month. The monthly firm capacities range from a low of 82,747 MMBTU/day in February to a high of 307,840MMBTU/day in August.

As shown on Attachment PME-17RB, the Base, Block I, Block II (Permian to Topock only), Block III, Line 2000 and Line 2000 Power Up capacity allocations are anticipated to be firm to APS and can be relied on to transport gas up to the level specified. This provides assurance that a certain amount of gas-fired generation will be able to run to serve the Company's power demands. Although technically all of the Block II capacity is recallable by California shippers through 2005, the Block II San Juan to Topock capacity suffers from north-south flow limitations and therefore has yet lower reliability than the other capacity allocations. At the time of the Company's original filing, the conversion from the Full Requirements Service to CD Service had not yet occurred, which meant that the only firm capacity allocation that was known and measurable was the Base and Line 2000 capacity. APS had little evidence on which to assess the amount of Block I, Block II, and Block III capacity that would be available to APS on a reliable basis. Moreover, the Line 2000 Power Up capacity also was unknown because the likelihood and size of its construction was still in question. As a result, APS' filing reflected an expectation that, in order to meet our reliability needs, APS would be forced to buy firm transport capacity in the capacity release market to reserve an appropriate level of pipeline capacity to meet our peak demand days. All transport requirements above the Base and Line 2000 allocations – 106,591 MMBTU/day on average – were modeled as incremental purchases.

Since September 2003, our experience under the CD service appears to indicate that it is appropriate to assume that Block I and Block III capacity should be available on a reliable basis and that, absent a must flow order, Block II (Permian to Topock) capacity also should be available on a reliable basis. Recognizing that the El Paso system utilization has been relatively low during this same period, likely as a result of the very low spark spreads in the market and the corresponding weak demand for gas-fired generation in the region, APS is revising its estimates to reflect the amount of the capacity that is likely to be available on a routine basis. APS has therefore made the corresponding adjustment to its purchases of incremental transport to reflect the likelihood that all of the Block I, Block III, and the Permian to Topock portion of our Block II capacity will be available. In addition, our adjustments reflect the fact that all of the Line 2000 Power Up will be available for use. These revisions to the Company's estimates of firm transportation eliminate net purchases of additional capacity of $7.1 million.

Q. WHAT IS THE IMPACT OF INCREMENTAL GAS TRANSPORTATION CAPACITY PURCHASES ON THE DISPATCH OF THE APS GENERATING UNITS?

A. Under this new structure, any transportation for natural gas burns above the FERC CD allocation must be purchased from the capacity release market. These incremental costs must be included in the economic decision-making process of dispatching generating units and purchasing power. When the El Paso tariff rate of $0.31/MMBTU is included in the dispatch logic, the Company experiences a reduction in off-system sales margin of $1.1 million.

Q. ARE THE ADJUSTMENTS YOU HAVE DESCRIBED THE SAME ADJUSTMENTS TESTIFIED TO BY MR. SMITH?

A. In part. Mr. Smith's recommendation on the amount of the El Paso CD capacity that should be treated as firm is very similar to mine, but his rationale is flawed. The principal reason that the Company can propose much lower costs for firm transportation is that the demand for natural gas is lower as a result of the low market spark spreads I described earlier. Because Mr. Smith's recommendation is based on a gas burn expectation that is much higher than my own, I believe that we could potentially harm the reliability of the APS system if we were to operate in the manner he suggests. If we had not lowered our burn projections, we could not agree with Mr. Smith's recommendation.

In particular, Mr. Smith suggests that 75% of the Block and Power Up capacity should be treated as firm capacity. While it is true that the Power Up portion of this capacity has become more certain (and is expected to be complete by the third quarter of this year), all of the Block II capacity remains subject to recall from California shippers and portions of the Block II capacity are subject to El Paso system flow restrictions. Mr. Smith searches for possible outcomes where the recall condition may not be an important economic issue and highlights on page 29 of his testimony, as an example, the case where California shippers are recalling capacity "for economic reasons (i.e., because it provides them access to gas priced below that available on other pipelines)." Mr. Smith goes on further to say that in such a case, "APS/PWEC *might* be able to replace the recalled capacity with purchases in the release market at a limited incremental cost" (emphasis added).

Q. DO YOU AGREE THAT SUCH A SITUATION COULD BE POSSIBLE?

A. While I agree that this may be a possible outcome, it certainly is neither assured nor even likely. APS buys firm capacity to ensure system reliability and cannot take the risk that capacity may not be available on days of peak demand. As Mr. Smith correctly points out, turned back capacity is most likely to be recalled by California shippers during on-peak months, when demand is very high. Because weather patterns tend to be regional and weather fluctuations are the source of most of the Company's near-term power demand volatility, it is more likely than not that on the Company's highest demand days, APS and the rest of the region will be using more gas-fired generation than typical. In such a case, transport capacity is at greater risk of being in short supply. Furthermore, when the market spark spreads increase, gas-fired generation also will increase, putting added pressure on pipeline capacity that is not there today.

Q. WHAT WOULD HAPPEN IF THERE WERE INSUFFICIENT PIPELINE CAPACITY AVAILABLE ON DAYS OF HIGHEST GAS DEMAND?

A. The short answer is that APS would not be able to burn as much gas as would be economic on that day and would be forced into the market for more expensive power. Without having reserved the capacity on the power side, the Company also runs the risk of not finding sufficient quantities of power on those high demand days. Again, those are the days that all utilities in the region are most likely to be scrambling to find all available megawatts and MMBTU of gas that can be converted to megawatts.

Q. CAN MR. SMITH'S RECOMMENDATION ON THE TREATMENT OF RECALLABLE PIPELINE CAPACITY ENSURE THAT ADEQUATE CAPACITY WILL BE AVAILABLE ON PEAK SUMMER DAYS OR, FOR THAT MATTER, ON OTHER SUMMER DAYS?

A. No. That is why such a casual recommendation threatens our system reliability.

Q. IF THE COMMISSION WERE TO ADOPT YOUR RECOMMENDATIONS ON THESE FOUR ISSUES, WOULD APS BE LESS LIKELY TO NEED A FUEL ADJUSTMENT MECHANISM?

A. No. My recommendations are based on the best available knowledge we have today. Although the adoption of these recommendations is important for the Company to recover its legitimate and prudently incurred costs, the issues I have raised should serve as a reminder of the intense volatility that surrounds fuel and purchased power costs. Uncertainty is rampant in the future direction of natural gas and power prices and the related spark spreads, and is clearly present in the transition to the new natural gas pipeline allocations.

Establishing a PSA mechanism as described in Mr. Robinson's testimony only makes sense. Our estimates on these issues could be wrong because of the nature of their unpredictability, and so long as they are not wrong by much, the Company can manage through the deviations. Some of these issues, however, have the potential for large deviations and are outside of the Company's control. In that event, it clearly makes sense for the Company to get a more immediate recovery of those costs. The results have the potential to be cost reductions, as well, and the Company believes that those cost savings also should be shared with customers on a more timely basis, just as they would share any cost increases on a more timely basis. Gas transport capacity and nuclear plant performance both are good examples of where customers could gain with much better than expected outcomes.

VI. REBUTTAL TO DR. BERRY

Q. DO YOU AGREE WITH DR. BERRY'S ARGUMENT AT PAGES 4-12 OF HIS TESTIMONY THAT WIND ENERGY IS A SUITABLE HEDGE AGAINST VOLATILE NATURAL GAS PRICES?

A. No, I do not. To qualify as a reliable hedge, a hedging instrument or product must provide certainty in both delivered volumes and price. To the extent that either one of these components is variable, the product loses its effectiveness in serving as a hedge against uncertainty and volatility. As Dr. Berry correctly points out in his testimony, wind energy is an intermittent source of power, which means that the timing of when the energy is being produced is uncertain from day to day and variable over the course of the year. Moreover, the wind energy resources that might be most available to the Company generally are less available during the peak summer demand period when displacing natural gas would be most valuable. Additionally, because wind energy production will vary considerably not only from day-to-day and season to season, but also from year to year, it would be difficult for the company to plan ahead how much gas to secure. As Dr. Berry also points out, because wind energy is intermittent, the level of operating reserves and ancillary services required to protect the system will naturally increase. These reserves more than likely will have to be in the form of gas-fired generating capacity.

The lower reliability of wind energy means not only that gas-fired units must be used to back it up, but also the predictability of when the energy will be available and what other resources it might be displacing are unknown. With Dr. Berry's recommendation, we would find ourselves in the unique position of having to use gas-fired generation to fill in when wind is unavailable, but the lack of predictability means that we will have a reduced ability to hedge those increased gas fuel costs.

VII. <u>OCTOBER 29, 2003 LETTER FROM COMMISSIONER GLEASON</u>

Q. IN HIS OCTOBER 29, 2003 LETTER FILED IN THIS DOCKET, WHAT DID COMMISSIONER GLEASON REQUEST?

A. Among other questions asked by Commissioner Gleason, he asked under the heading "PWEC Units Operating Results," item A., that APS specifically "Break out the amount in column R [on Schedule C-2, page 3 of 10 of the Company's filing] for each line item for each of the identified PWEC assets and any other significant PWEC assets such as the Redhawk Transmission. The sum of the amounts for the individual PWEC assets on each line should reconcile to the corresponding line on Schedule C-2 of the filing." I am providing the requested details for the total Company amount on line 3, Operating Revenue Less Purchased Power & Fuel Costs. APS Witness Alan Propper discusses the jurisdictionalization of these amounts.

Q. WHAT IS THE AMOUNT SHOWN IN COLUMN R ON LINE 3 OF SCHEDULE C-2?

A. The total increase in revenue less purchased power and fuel expenses in Column Q is $91,749,000. The ACC-jurisdictional amount in Column R is $91,207,000. Of the amount in Column Q, the increase associated with including the PWEC assets in the dispatch of the system is $67 million. The remaining $25 million reflects the inclusion of the PWEC Units-related debt as part of the Company's permanent capital structure and is discussed in Mr. Robinson's testimony.

Q. HOW DO EACH OF THE "IDENTIFIED PWEC ASSETS" ACCOUNT FOR THE $67 MILLION CHANGE?

A. The analysis we conducted shows that Redhawk Units 1 and 2 together save APS $46.8 million in annual fuel and purchased power expenses net of any off-system sales margin. West Phoenix CC 5 contributes an additional $15.1 million, while

West Phoenix CC4 accounts for \$3.3 million and Saguaro CT 3 produces \$1.5 million. The results are included in Mr. Robinson's Schedule DGR-8RB.

Q. HOW DID YOU CONDUCT THE ANALYSIS?

A. We started with the simulation that did not include the PWEC units and added them in one at a time until all units were included in the dispatch. The change in net system costs (fuel and purchased power expenses net of any off-system sales margin) between each of these simulations produced the values in Schedule DGR-8RB and Attachment PME-18RB. As a practical matter, because the Redhawk units are identical, to save processing time, they were included in the dispatch in one step instead of two separate simulation runs. Additionally, the consequence of including a subset of the PWEC assets in rate base is the termination of the entire Track B contract awarded to PWEC. This is also reflected in the first step. Breaking this amount out separately, APS first sees an increase in costs from the termination of the PWEC Track B contract of \$19.6 million. That is, at the original pro forma fuel and power price levels, the PWEC Track B contract value is \$19.6 million below a pure market value. The net savings from the Redhawk units relative to purchasing at market is \$66.4 million. The following table summarizes the incremental savings (or costs):

Terminate Track B Contract	(\$19.6 million)
Include Redhawk	\$66.4 million
Include West Phoenix CC5	\$15.1 million
Include West Phoenix CC4	\$ 3.3 million
Include Saguaro CT3	\$ 1.5 million
Total Savings	\$66.7 million

I should also note that the savings for each individual plant are sensitive to the order in which they are included. Savings associated with West Phoenix and Saguaro would be greater if they were included before the Redhawk units.

Q. CAN YOU ALSO EXPLAIN THE RELATIONSHIP OF THE REVENUE RECOGNIZED IN THE PROPOSED PWEC ADJUSTMENT AND THE MARKET REVENUE FOR TOTAL PWEC ASSETS SHOWN IN BHATTI WORKPAPER APB-23WP 2/16 "BENEFITS OF RATEBASING PWEC ASSETS TO APS CUSTOMERS"?

A. There are three principal reasons for the difference between the two numbers ($57 million and $357 million) mentioned in the question. Let me address each of them in turn.

Perhaps the largest reason is that the $57 million includes a margin on off-system sales (gross revenues from such sales minus the gross fuel expenses) and the $357 million represents a gross revenue number only (*i.e.*, fuel expenses have not yet been deducted to find the applicable margin). Another significant difference is that the $57 million includes the market value of the portion of the PWEC units that is not needed to serve native load customers, which in this case amounts to less than 20% of the total output of these units. The $357 million calculates the market value of 100% of the PWEC unit output. Adjusting for these two differences (and acknowledging that the market prices in the two sets of workpapers are slightly different), the equivalent gross market revenues implied in Mr. Robinson's workpapers equate to $378 million, slightly higher than the $357 million shown by Mr. Bhatti.

Finally, some $25.1 million of the $56.8 million referenced in Adjustment No. 9 is not attributable to sales from the PWEC units but reflects the inclusion of the $500 million debt associated with the PWEC assets in the Company's capital structure, which had the effect of both reducing weighted average debt costs and increasing leverage under the rate-basing proposal. There was no easy way of reflecting this effect as, say, a reduction in the operating costs or capital costs of the PWEC units, so, to make sure this benefit to customers did not get lost, APS added it into the category of increased revenues.

VIII. CONCLUSION

Q. DO YOU HAVE ANY FINAL REMARKS?

A. The volatility of natural gas and purchased power, as well as of spark spreads, has been well-documented over the last few years and is expected to continue into the foreseeable future. This volatility can be most effectively addressed through the implementation of a PSA and the Company has proposed a PSA that provides an appropriate incentive to the Company to manage its fuel and purchased power costs, while ensuring that customers have adequate price signals. Moreover, natural gas prices are anticipated to remain high and volatile. Staff and intervenor concerns with the proposed PSA have either been addressed by Mr. Robinson or, as I discuss in my rebuttal, are unfounded. Along with several other factors, those higher prices require the revisiting of the fuel expense pro forma originally proposed by the Company in its June 2003 filing to make that adjustment more reflective of when rates are likely to become effective. PVNGS's operations have been exceptional. To penalize APS because it cannot match record performance every year is inappropriate. Moreover, Staff's adjustment has been miscalculated

Q. DOES THIS CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

ATTACHMENT PME - 1RB

HISTORIC SPOT MARKET NATURAL GAS and POWER PRICES

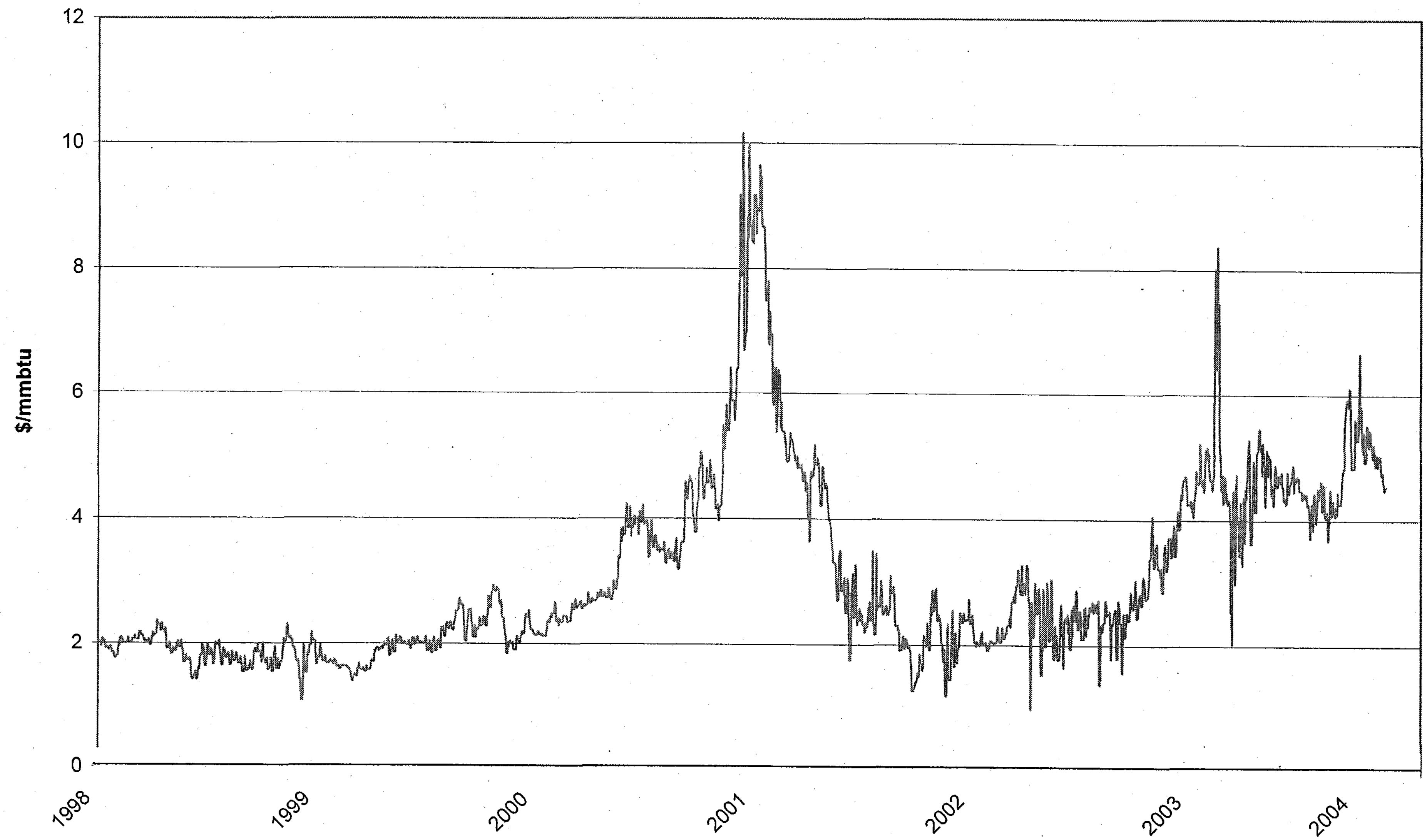
NATURAL GAS ($/mmbtu)	1998	1999	2000	2001	2002	2003	1998-2003	7/1/01 - 2003
Henry Hub								
Average	2.08	2.26	4.29	3.98	3.34	5.47	3.53	3.97
Maximum	2.65	3.08	10.53	10.53	5.33	18.60	18.60	18.60
Minimum	1.01	1.62	2.15	1.74	1.98	3.99	1.01	1.74
Standard Deviation	0.25	0.36	1.74	1.86	0.72	1.31	1.66	1.48
San Juan								
Average	1.86	2.05	3.87	3.52	2.63	4.59	3.07	3.30
Maximum	2.36	2.93	10.16	9.66	4.69	8.36	10.16	8.36
Minimum	1.08	1.39	2.13	1.18	1.00	2.03	1.00	1.00
Standard Deviation	0.22	0.34	1.61	1.90	0.66	0.69	1.49	1.24
Southern California Border								
Average	2.26	2.31	6.33	7.77	3.13	5.11	4.48	3.79
Maximum	2.88	3.14	59.42	36.79	4.88	10.01	59.42	10.01
Minimum	1.83	1.64	2.30	1.40	2.07	3.79	1.40	1.40
Standard Deviation	0.18	0.39	7.31	6.40	0.65	0.78	4.55	1.27
POWER ($/mwh)								
Palo Verde On-Peak								
Average	28.14	30.80	110.83	120.82	32.11	48.67	61.18	40.36
Maximum	93.84	76.48	519.29	537.02	70.09	118.21	537.02	118.21
Minimum	8.56	16.65	23.00	15.50	18.00	28.52	8.56	15.50
Standard Deviation	12.42	9.72	93.41	106.00	7.13	10.30	68.82	13.41

Sources:

Gas Daily - Reprinted with Permission of Platts 1998-2003

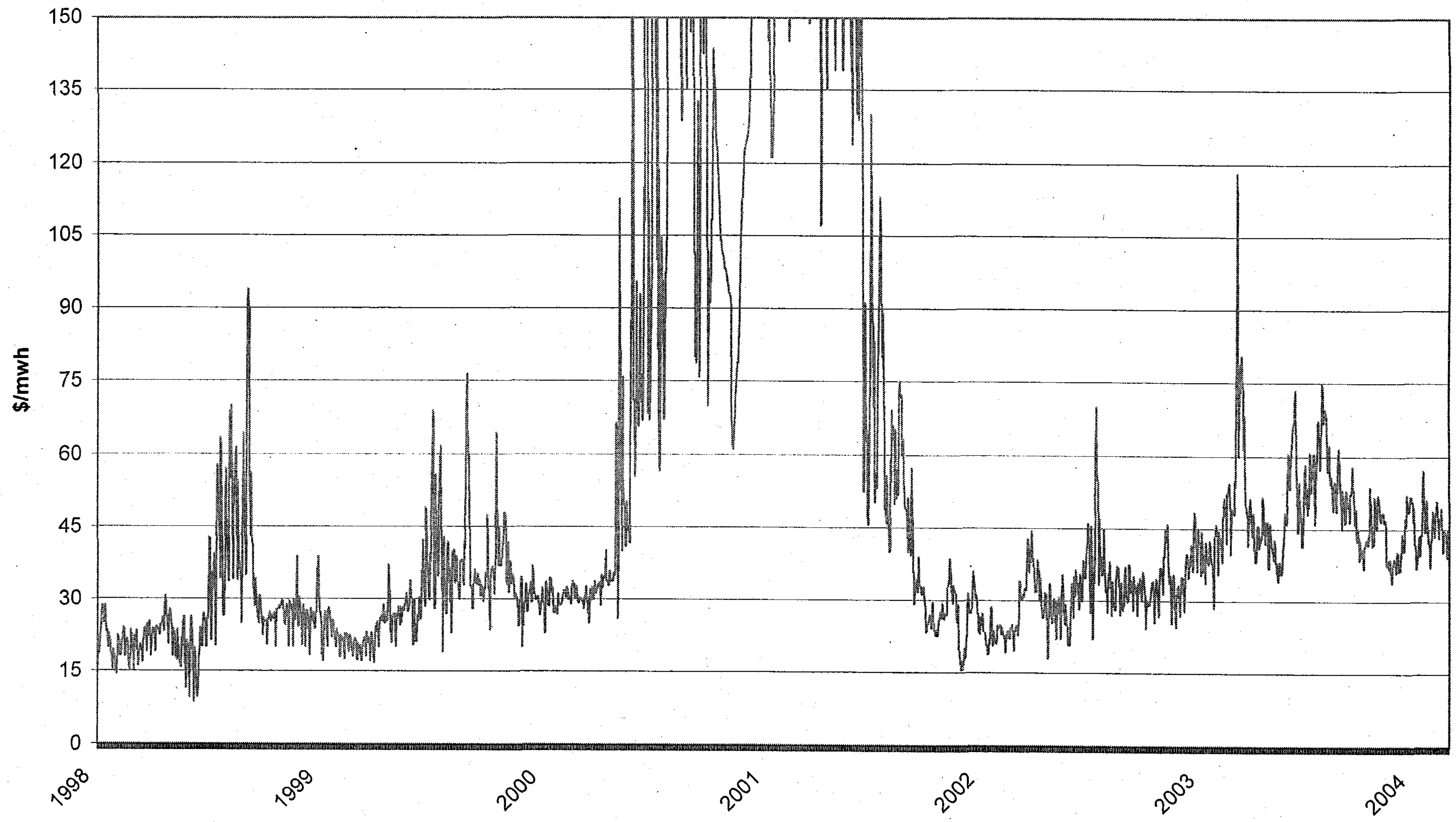
Dow Jones Palo Verde Electricity Indexes 1998-2003

ATTACHMENT PME - 2RB
Daily Spot Market Natural Gas Prices
San Juan Basin
1998-2004

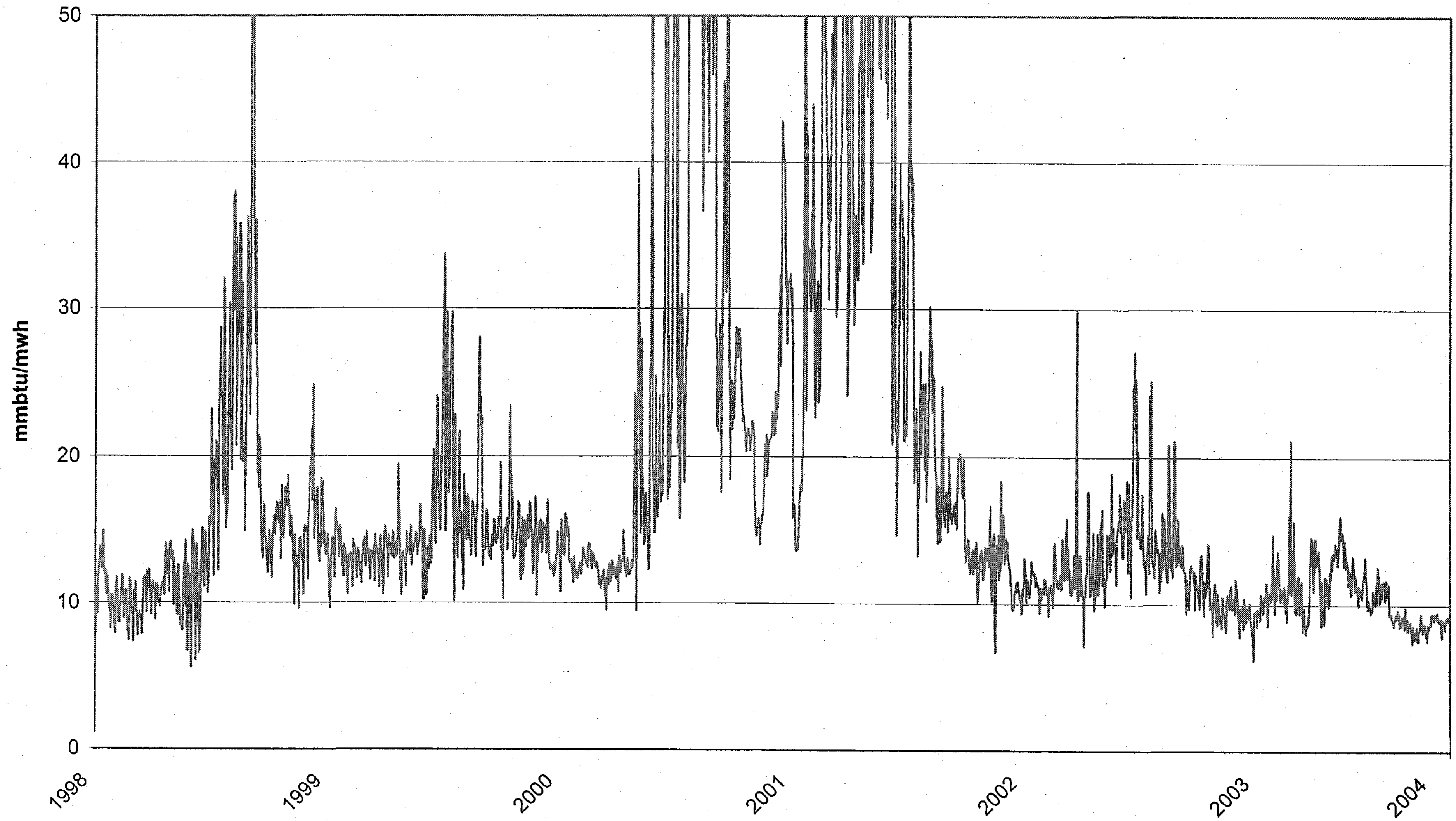


Gas Daily - Reprinted with Permission of Platts

ATTACHMENT PME - 3RB
Daily Spot Market Power Prices
Palo Verde On Peak
1998-2004



ATTACHMENT PME - 4RB
Daily Spot Market Spark Spreads
Palo Verde On-Peak / San Juan Basin Gas
1998-2004



Attachment PME-5RB
Forward Market Natural Gas and Power Prices

	Delivery Year*			
	2002	**2003**	**2004**	**2005**
Natural Gas Price ($/MMBTU)				
Henry Hub				
Mean	3.39	3.61	4.19	4.05
Max	5.07	4.68	5.68	5.07
Min	2.44	2.68	3.07	3.08
Std Dev.	0.80	0.51	0.66	0.51
San Juan				
Mean	3.15	3.35	3.86	3.71
Max	4.86	4.57	5.02	4.43
Min	2.22	2.46	2.95	3.08
Std Dev.	0.81	0.50	0.51	0.35
Power Prices ($/MWH)				
PV On-Peak				
Mean	74.66	47.71	43.99	42.30
Max	180.89	91.25	67.50	60.98
Min	32.15	30.50	18.86	18.86
Std Dev.	37.63	13.58	7.79	6.01

* Prices for 2002 delivery reflect market quotations from 6/1/1999 to 12/31/2001.
Prices for 2003 delivery reflect market quotations from 1/1/2000 to 12/31/2002.
Prices for 2004 and 2005 delivery reflect market quotations for 1/1/2001 to 12/31/2003.

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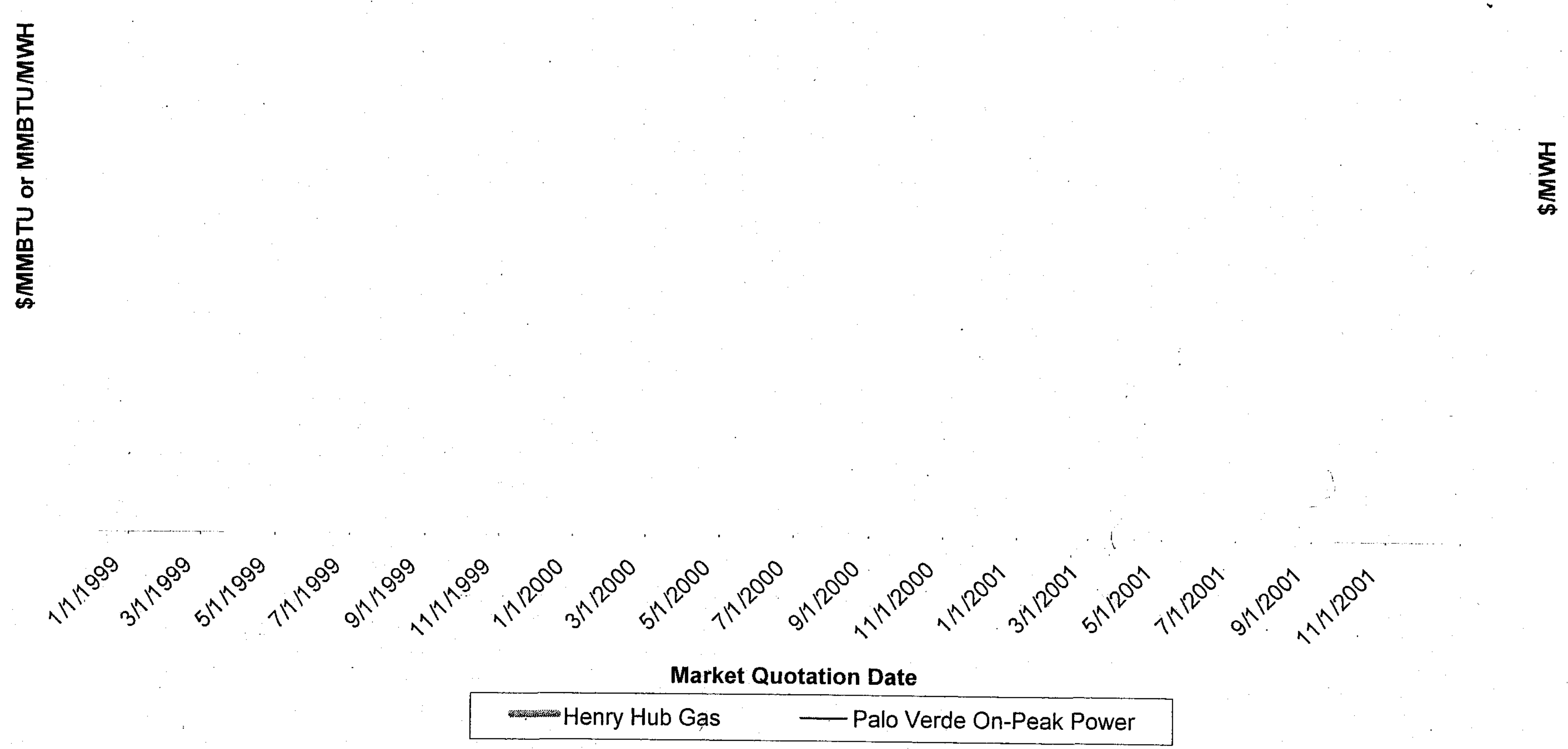
Confidential

Attachment PME-6RB
Forward Market Natural Gas and Power Prices
2002 Calendar Year Deliverv



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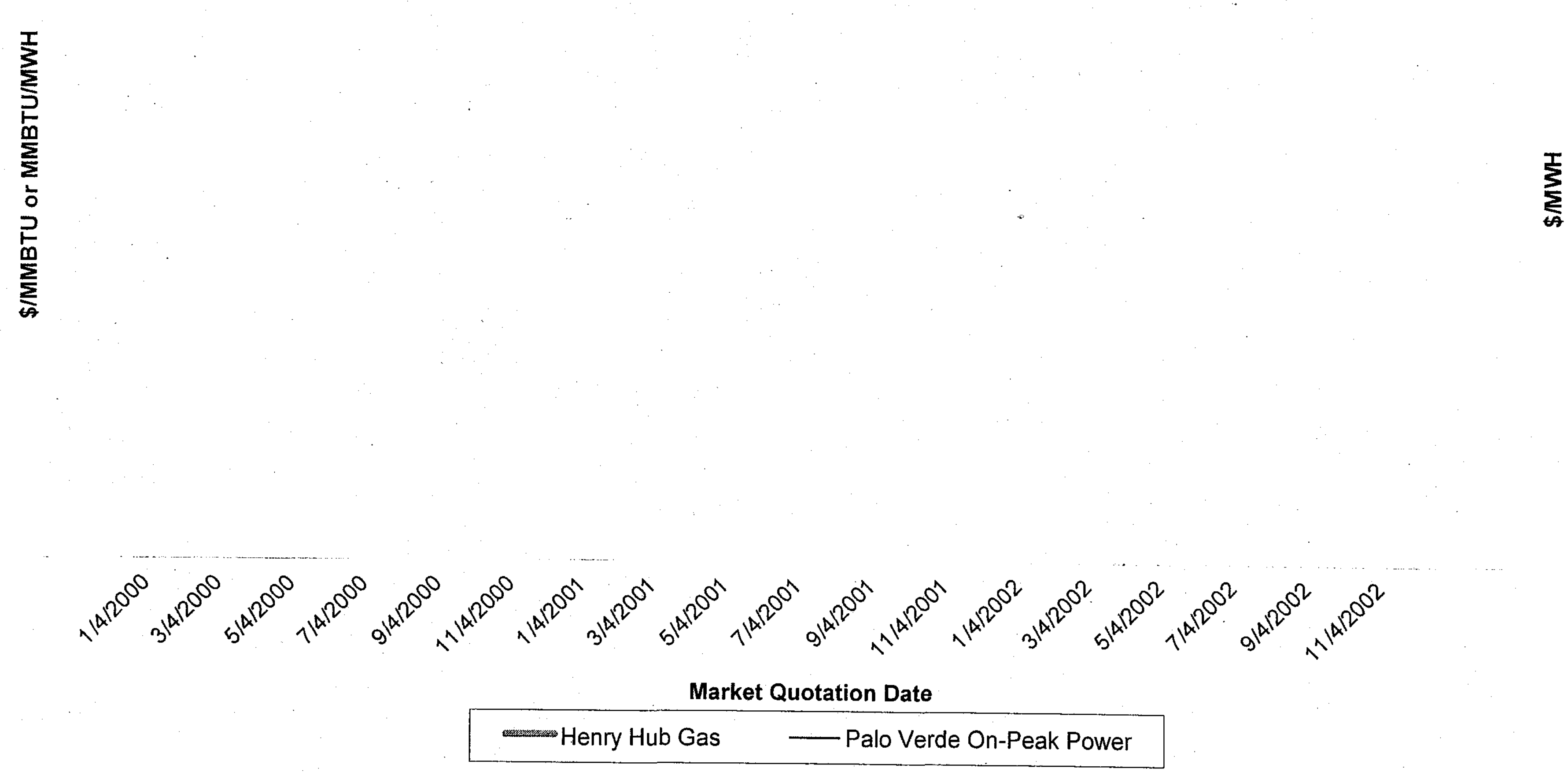
Confidential

Attachment PME-7RB
Forward Market Natural Gas and Power Prices
2003 Calendar Year Delivery



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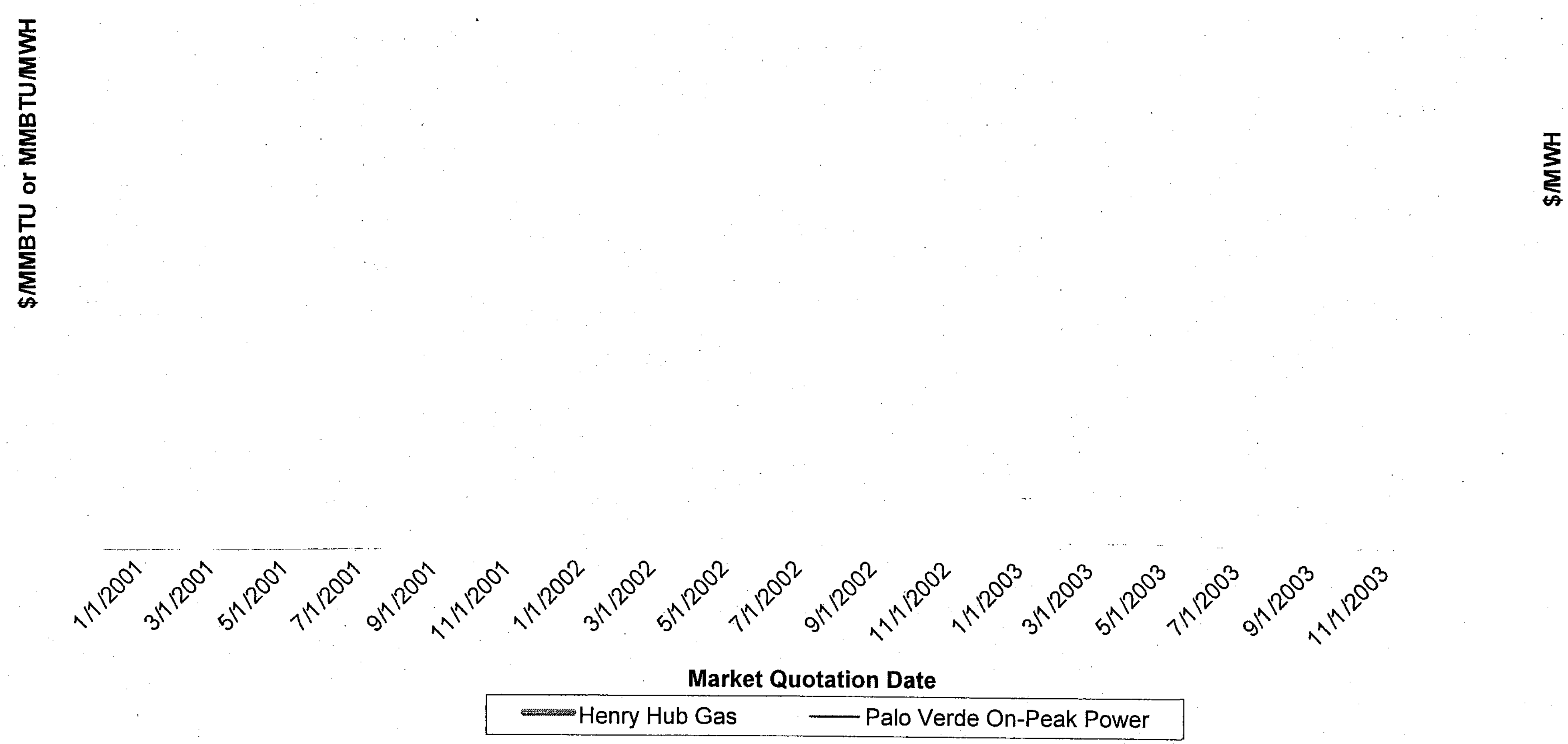
Attachment PME-8RB
Forward Market Natural Gas and Power Prices
2004 Calendar Year Delivery



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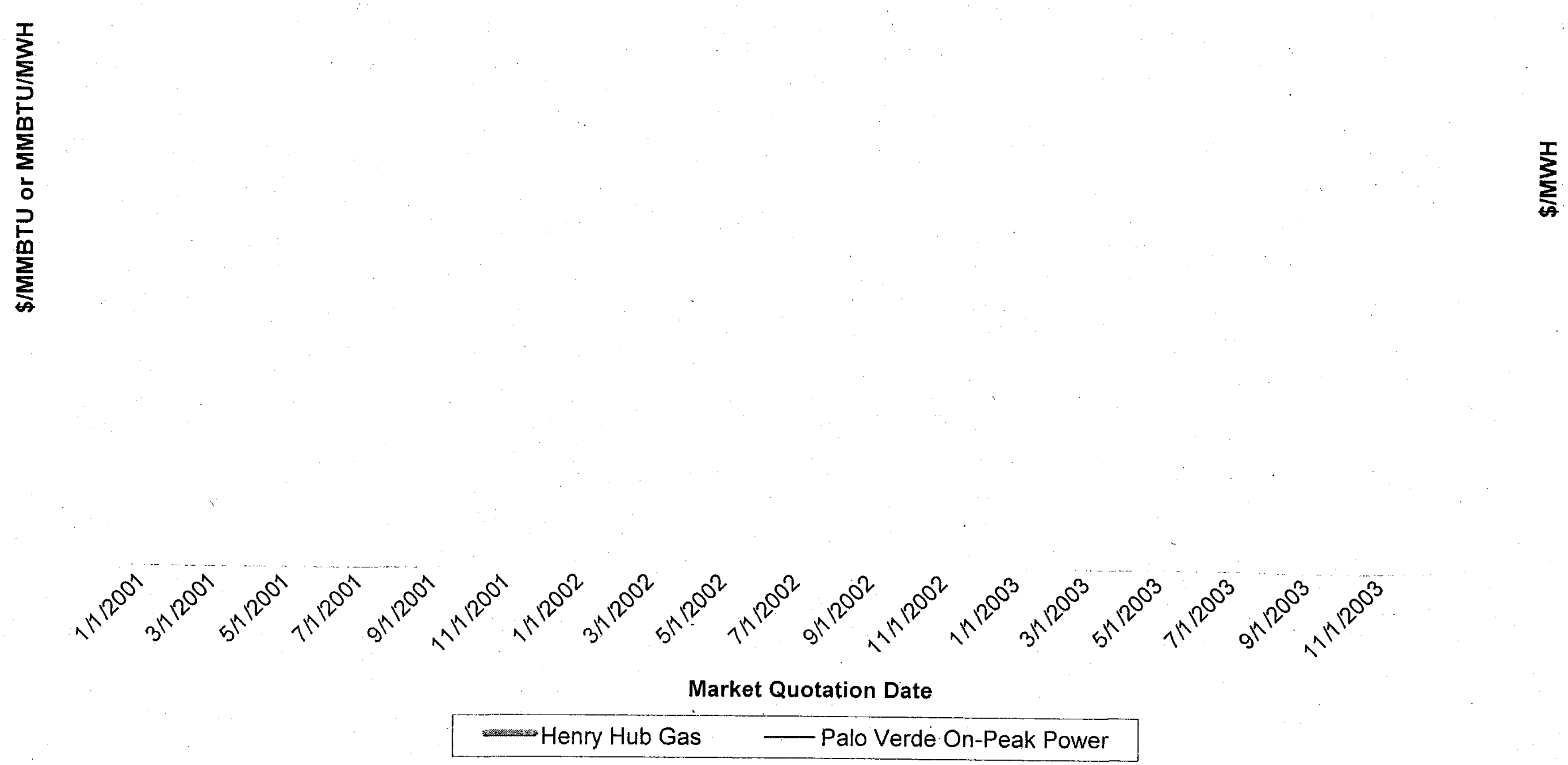
Attachment PME-9RB
Forward Market Natural Gas and Power Prices
2005 Calendar Year Delivery



ATTACHMENT PME-10RB

AVERAGE ANNUAL COSTS EXCLUDING FUEL AND PURCHASED POWER

Cost ($000)	1999	2000	2001	2002	2003
O&M	437,125	430,092	465,561	495,845	513,604
Depreciation and Amortization*	252,331	267,479	275,893	284,640	303,240
Other Taxes	96,579	99,730	101,077	107,925	108,852
Interest net of capitalized interest	136,353	133,097	118,211	121,616	143,568
Preferred Dividends	1,016	-	-	-	-
Total	923,404	930,398	960,742	1,010,026	1,069,264
Retail Sales (GWh)	21,075	22,535	23,399	23,362	24,563
Unit Cost (¢/kWh)					
O&M	2.07	1.91	1.99	2.12	2.09
Depreciation and Amortization	1.20	1.19	1.18	1.22	1.23
Other Taxes	0.46	0.44	0.43	0.46	0.44
Interest net of capitalized interest	0.65	0.59	0.51	0.52	0.58
Preferred Dividends	0.00	-	-	-	-
Total	4.38	4.13	4.11	4.32	4.35

*Excludes regulatory asset amortization

Attachment PME-11RB
Example of Simple Hedge for Natural Gas

Year 1	
1. Company predicts gas burn for Year 3 to be	20,000,000 mmbtu
2. Current prices for natural gas in Year 3	
a. Henry Hub	$4.00/mmbtu
b. San Juan	$3.75/mmbtu
c. San Juan - Henry Hub Basis	$(0.25)/mmbtu
3. Company buys futures contracts at Henry Hub to cover Year 3 demand (1 x 2a)	($80.0 million)

Year 3	
4. Current prices for natural gas in Year 3	
a. Henry Hub	$6.00/mmbtu
b. San Juan	$5.75/mmbtu
c. San Juan - Henry Hub Basis	$(0.25)/mmbtu
5. Company buys San Juan gas to meet demand (1 x 4b)	($115.0 million)
6. Company liquidates futures at Henry Hub (1 x 4a)	+120.0 million
7. Net hedged cost of Year 3 gas (3 + 5 + 6)	($75.0 million)
8. Average hedged cost of Year 3 gas (7 / 1)	$3.75/mmbtu

ATTACHMENT PME-12RB

NORMALIZED PALO VERDE PLANNED OUTAGE DAYS

PLANNED OUTAGE DAYS	ACTUAL						
UNIT	2000	2001	2002	2000-2002 AVERAGE Days	2003 BUDGET	NORMALIZING ADJUSTMENT	NORMALIZED AMOUNT
1	0	44	33	26	0	0	0
2	33	0	32	22	76	(40)	36
3	32	37	0	23	36	(2)	34
TOTAL	65	81	65	70	112	(42)	70

PLANNED OUTAGE MW-DAYS		ACTUAL						
UNIT	Capacity	2000	2001	2002	2000-2002 AVERAGE MW-Days	2003 BUDGET	NORMALIZING ADJUSTMENT	NORMALIZED AMOUNT
1	361.7	0	15,915	11,936	9,284	0	0	0
2	361.7	11,936	0	11,574	7,837	27,489	(14,468)	13,021
3	362.9	11,613	13,427	0	8,347	13,064	(726)	12,339
TOTAL	1,086.3	23,549	29,342	23,511	25,467	40,554	(15,194)	25,360

ATTACHMENT PME-13RB

HISTORICAL PALO VERDE CAPACITY FACTOR

ANNUAL CAPACITY FACTOR

UNIT	1999	2000	2001	2002	2003
1	88.7	100.4	87.8	89.1	97.2
2	90.0	87.2	92.6	92.0	77.6
3	100.3	90.3	83.9	102.0	87.5
TOTAL	93.0	92.6	88.1	94.4	87.4

3-YEAR AVERAGE ANNUAL CAPACITY FACTOR

UNIT	1999-2001	2000-2002	2001-2003
1	92.3	92.4	91.4
2	89.9	90.6	87.4
3	91.5	92.1	91.1
TOTAL	91.2	91.7	90.0

901 Supervision.

This account shall include the cost of labor and expenses incurred in the general direction and supervision of customer accounting and collecting activities. Direct supervision of a specific activity shall be charged to account 902, Meter Reading Expenses, or account 903, Customer Records and Collection Expenses, as appropriate. (See operating expense instruction 1.)

902 Meter reading expenses.

This account shall include the cost of labor, materials used and expenses incurred in reading customer meters, and determining consumption when performed by employees engaged in reading meters.

ITEMS

Labor:

1. Addressing forms for obtaining meter readings by mail.
2. Changing and collecting meter charts used for billing purposes.
3. Inspecting time clocks, checking seals, etc., when performed by meter readers and the work represents a minor activity incidental to regular meter reading routine.
4. Meter reading—small consumption, and obtaining load information for billing purposes. (Exclude and charge to account 878, Meter and House Regulator Expenses, or to account 903, Customer Records and Collection Expenses, as applicable, the cost of obtaining meter readings, first and final, if incidental to the operation of removing or resetting, sealing or locking, and disconnecting, or reconnecting meters.)
5. Measuring gas—large consumption, including reading meters, changing charts, calculating charts, estimating lost meter registrations, determining specific gravity, etc., for billing purposes.
6. Computing consumption from meter reader's book or from reports by mail when done by employees engaged in reading meters.
7. Collecting from prepayment meters when incidental to meter reading.
8. Maintaining record of customers' keys.
9. Computing estimated or average consumption when performed by employees engaged in reading meters.

Materials and expenses:

10. Badges, lamps, and uniforms.
11. Demand charts, meter books and binders and forms for recording readings, but not the cost of preparation.
12. Postage and supplies used in obtaining meter readings by mail.
13. Transportation, meals and incidental expenses.

903 Customer records and collection expenses.

This account shall include the cost of labor, materials used and expenses incurred in work on customer applications, contracts, orders, credit investigations, billing and accounting, collections and complaints.

Items

Labor:

1. Receiving, preparing, recording and handling routine orders for service, disconnections, transfers or meter tests initiated by the customer, excluding the cost of carrying out such orders, which is chargeable to the account appropriate for the work called for by such orders.
2. Investigations of customers' credit and keeping of records pertaining thereto, including records of uncollectible accounts written off.
3. Receiving, refunding or applying customer deposits and maintaining customer deposit, line extension, and other miscellaneous records.
4. Checking consumption shown by meter readers' reports where incidental to preparation of billing data.
5. Preparing address plates and addressing bills and delinquent notices.
6. Preparing billing data.
7. Operating billing and bookkeeping machines.
8. Verifying billing records with contracts or rate schedules.
9. Preparing bills for delivery, and mailing or delivering bills.
10. Collecting revenues, including collection from prepayment meters unless incidental to meter reading operations.
11. Balancing collections, preparing collections for deposit, and preparing cash reports.
12. Posting collections and other credits or charges to customer accounts and extending unpaid balances.
13. Balancing customer accounts and controls.
14. Preparing, mailing, or delivering delinquent notices and preparing reports of delinquent accounts.
15. Final meter reading of delinquent accounts when done by collectors incidental to regular activities.
16. Disconnecting and reconnecting services because of nonpayment of bills.
17. Receiving, recording, and handling of inquiries, complaints, and requests for investigations from customers, including preparation of necessary orders, but excluding the cost of carrying out such orders, which is chargeable to the account appropriate for the work called for by such orders.

18. Statistical and tabulating work on customer accounts and revenues, but not including special analyses for sales department, rate department, or other general purposes, unless incidental to regular customer accounting routines.
19. Preparing and periodically rewriting meter reading sheets.
20. Determining consumption and computing estimated or average consumption when performed by employees other than those engaged in reading meters.

Materials and expenses:

21. Address plates and supplies.
22. Cash overages and shortages.
23. Commissions or fees to others for collecting.
24. Payments to credit organizations for investigations and reports.
25. Postage.
26. Transportation expenses, including transportation of customer bills and meter books under centralized billing procedure.
27. Transportation, meals, and incidental expenses.
28. Bank charges, exchange, and other fees for cashing and depositing customers' checks.
29. Forms for recording orders for services, removals, etc.
30. Rent of mechanical equipment.

NOTE: The cost of work on meter history and meter location records is chargeable to account 878, Meter and House Regulator Expenses.

904 Uncollectible accounts.

This account shall be charged with amounts sufficient to provide for losses from uncollectible utility revenues. Concurrent credits shall be made to account 144, Accumulated Provision for Uncollectible Accounts—Credit. Losses from uncollectible accounts shall be charged to account 144.

905 Miscellaneous customer accounts expenses.

This account shall include the cost of labor, materials used and expenses incurred not provided for in other accounts.

ITEMS

Labor:

1. General clerical and stenographic work.
2. Miscellaneous labor.

Materials and expenses:

3. Communication service.
4. Miscellaneous office supplies and expenses and stationery and printing other than those specifically provided for in accounts 902 and 903.

907 Supervision.

This account shall include the cost of labor and expenses incurred in the general direction and supervision of customer service activities, the object of which is to encourage safe, efficient and economical use of the utility's service. Direct supervision of a specific activity within customer service and informational expense classification shall be charged to the account wherein the costs of such activity are included. (See operating expense instruction 1.)

908 Customer assistance expenses.

This account shall include the cost of labor, materials used, and expenses incurred in providing instructions or assistance to customers, the object of which is to promote safe, efficient and economical use of the utility's service.

ITEMS

Labor:

1. Direct supervision of department.
2. Processing customer inquiries relating to the proper use of gas equipment, the replacement of such equipment and information related to such equipment.
3. Advice directed to customers as to how they may achieve the most efficient and safest use of gas equipment.
4. Demonstrations, exhibits, lectures, and other programs designed to instruct customers in the safe, economical or efficient use of gas service, and/or oriented toward conservation of energy.
5. Engineering and technical advice to customers, the object of which is to promote safe, efficient and economical use of the utility's service.

Materials and expenses:

6. Supplies and expenses pertaining to demonstrations, exhibits, lectures, and other programs.
7. Loss in value on equipment and appliances used for customer assistance programs.
8. Office supplies and expenses.
9. Transportation, meals, and incidental expenses.

NOTE: Do not include in this account expenses that are provided for elsewhere, such as accounts 416, Costs and Expenses of Merchandising, Jobbing and Contract Work, 879, Customer Installations Expenses, and 912, Demonstrating and Selling Expenses.

909 Informational and instructional advertising expenses.

This account shall include the cost of labor, materials used and expenses incurred in activities which primarily convey information as to what the utility urges or suggests customers should do in utilizing gas service to protect health and safety, to encourage environmental protection, to utilize their gas equipment safely and economically, or to conserve natural gas.

ITEMS

Labor:

1. Direct supervision of informational activities.
2. Preparing informational materials for newspapers, periodicals, billboards, etc., and preparing and conducting informational motion pictures, radio and television programs.
3. Preparing informational booklets, bulletins, etc., used in direct mailings.
4. Preparing informational window and other displays.
5. Employing agencies, selecting media and conducting negotiations in connection with the placement and subject matter of information programs.

Materials and expenses:

6. Use of newspapers, periodicals, billboards, radio, etc., for informational purposes.
7. Postage on direct mailings to customers exclusive of postage related to billings.
8. Printing of informational booklets, dodgers, bulletins, etc.
9. Supplies and expenses in preparing informational materials by the utility.
10. Office supplies and expenses.

NOTE A: Exclude from this account and charge to account 930.2, Miscellaneous General Expenses, the cost of publication of stockholder reports, dividend notices, bond redemption notices, financial statements, and other notices of a general corporate character. Exclude also all expenses of a promotional, institutional, goodwill or political nature, which are includible in such accounts as 913, Advertising Expenses, 930.1, General Advertising Expenses, and 426.4, Expenditures for Certain Civic, Political and Related Activities.

NOTE B: Entries relating to informational advertising included in this account shall contain or refer to supporting documents which identify the specific advertising message. If references are used, copies of the advertising message shall be readily available.

910 Miscellaneous customer service and informational expenses.

This account shall include the cost of labor, materials used and expenses incurred in connection with customer service and informational activities which are not includible in other customer information expense accounts.

ITEMS

Labor:

1. General clerical and stenographic work not assigned to specific customer service and information programs.
2. Miscellaneous labor.

Materials and expenses:

3. Communication service.
4. Printing, postage and office supplies expenses.

911 Supervision.

This account shall include the cost of labor and expenses incurred in the general direction and supervision of sales activities, except merchandising. Direct supervision of a specific activity, such as demonstrating, selling, or advertising shall be charged to the account wherein the costs of such activity are included. (See operating expense instruction 1.)

912 Demonstrating and selling expenses.

This account shall include the cost of labor, materials used and expenses incurred in promotional, demonstrating, and selling activities, except by merchandising, the object of which is to promote or retain the use of utility services by present and prospective customers.

ITEMS

Labor:

1. Demonstrating uses of utility services.
2. Conducting cooking schools, preparing recipes, and related home service activities.
3. Exhibitions, displays, lectures, and other programs designed to promote use of utility services.
4. Experimental and development work in connection with new and improved appliances and equipment, prior to general public acceptance.
5. Solicitation of new customers or of additional business from old customers, including commissions paid employees.
6. Engineering and technical advice to present or prospective customers in connection with promoting or retaining the use of utility services.

ATTACHMENT PME-15RB

SUMMARY OF ADDITIONAL PRO FORMA ADJUSTMENTS TO FUEL AND PURCHASED POWER EXPENSE

	2003 ENERGY LEVELS						2002 ENERGY LEVELS		
BASE FUEL AND PURCHASED POWER ADJUSTMENTS	**CHANGE IN COST ($000)**		**NATIVE LOAD SALES (MWH)**		**AVERAGE COST ($/MWH)**		**RETAIL SALES (MWH)**		**CHANGE IN COST ($000)**
REMOVE 10% DISCOUNT TO 4/24/2003 FORWARD GAS PRICES									
Net Variable Cost Impact	15,705	÷	25,208,287	=	0.62	×	23,473,646	=	14,624
Gas Transportation Capacity Requirement	(3,640)	÷	25,208,287	=	(0.14)	×	23,473,646	=	(3,390)
UPDATE NATURAL GAS TRANSPORTATION CAPACITY AND DISPATCH EFFECTS									
Adjusted Firm Capacity Amounts	(7,630)	÷	25,208,287	=	(0.30)	×	23,473,646	=	(7,105)
HIGHER COAL COSTS RELATED TO NAVAJO NATION FUEL EXCISE TAX 2,431ktons X $0.124/ton = $301k	301	÷	25,208,287	=	0.01	×	23,473,646	=	280
ANNUALIZE SRP T&C DEMAND CHARGE TO YEAR-END 2004 LEVELS	2,513	÷	25,208,287	=	0.1	×	23,473,646	=	2,340
TOTAL	7,249								6,750

OFF-SYSTEM SALES MARGIN ADJUSTMENTS	**CHANGE IN COST ($000)**
REMOVE 10% DISCOUNT TO 4/24/2003 FORWARD GAS PRICES	
Net Variable Cost Impact	(16,096)
UPDATE NATURAL GAS TRANSPORTATION CAPACITY AND DISPATCH EFFECTS	
Incremental Cost Effect on Dispatch	(1,131)
TOTAL	(17,227)

ATTACHMENT PME-15RB

SUMMARY OF ADDITIONAL PRO FORMA ADJUSTMENTS TO FUEL AND PURCHASED POWER EXPENSE

TOTAL COMPANY FUEL AND PURCHASED POWER ADJUSTMENTS	CHANGE IN COST ($000)
1. REMOVE 10% DISCOUNT TO 4/24/2003 FORWARD GAS PRICES	
a. Net Variable Cost Impact	30,720
b. Gas Transportation Capacity Requirement	(3,390)
TOTAL	27,331
2. UPDATE NATURAL GAS TRANSPORTATION CAPACITY AND DISPATCH EFFECTS	
a. Adjusted Firm Capacity Amounts	(7,105)
b. Incremental Cost Effect on Dispatch	1,131
TOTAL	(5,974)
3. HIGHER COAL COSTS RELATED TO NAVAJO NATION FUEL EXCISE TAX 2,431ktons X $0.124/ton = $301k	280
4. ANNUALIZE SRP T&C DEMAND CHARGE TO YEAR-END 2004 LEVELS	2,340
TOTAL	23,977

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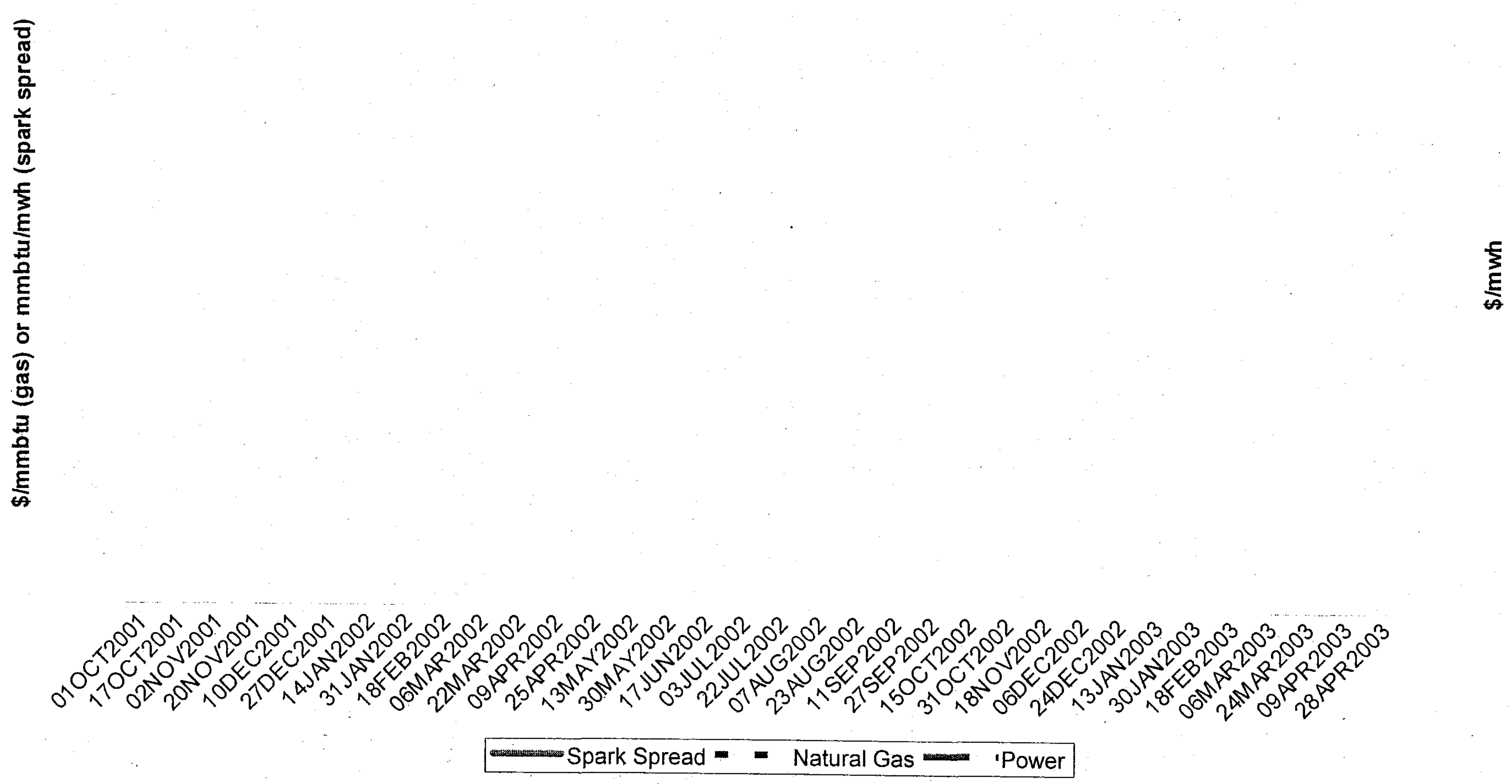
Attachment PME-16RB
Forward Market Quotations for Power and Natural Gas
May 2003 - April 2004 Delivery



ATTACHMENT PME-17RB

EL PASO PIPELINE CAPACITY AVAILABLE TO APS
(MMBTU/DAY)

(Mcf/d)	January	February	March	April	May	June	July	August	September	October	November	December	Annual Avg.
Base+Line 2000	68,448	51,805	59,708	90,843	101,153	121,777	156,240	168,037	142,171	128,420	87,878	73,849	104,194
Block I	482	364	455	770	925	1,243	1,596	1,718	1,335	1,097	673	520	932
BlockII - Permian to Topock	13,477	10,104	12,389	20,399	23,756	31,258	40,166	43,303	34,428	29,034	18,303	14,500	24,260
BlockII - San Juan to Topock	19,713	14,951	18,929	32,599	39,916	54,285	69,653	74,968	57,446	46,444	27,998	21,281	39,849
Block III	731	552	690	1,167	1,402	1,884	2,418	2,604	2,023	1,662	1,020	788	1,412
Power-Up	23,925	18,061	22,576	38,204	45,899	61,665	79,165	85,257	66,229	54,409	33,377	25,793	46,213
Grand Total (Mcf/d)	126,777	95,837	114,747	183,982	213,051	272,112	349,238	375,887	303,632	261,066	169,249	136,731	216,859
Grand Total (MMBtu/d)	129,692	98,041	117,386	188,214	217,951	278,370	357,270	384,533	310,615	267,071	173,142	139,875	221,847

(MMBtu/d)	January	February	March	April	May	June	July	August	September	October	November	December	Annual Avg.
Total Firm	109,526	82,747	98,022	154,865	177,117	222,837	286,015	307,840	251,848	219,559	144,500	118,105	181,082
Total Non-Firm	20,166	15,295	19,364	33,349	40,834	55,534	71,255	76,692	58,767	47,512	28,642	21,770	40,765
Maximum Daily Use	212,726	202,360	166,371	166,322	200,131	271,623	266,725	270,585	238,021	223,922	205,744	201,503	218,836
Incremental Capacity Purchase	103,200	119,614	68,349	11,457	23,014	48,787	(19,290)	(37,255)	(13,827)	4,364	61,244	83,398	37,754

ATTACHMENT PME-18RB

OPERATING REVENUE LESS FUEL AND PURCHASED POWER EXPENSE
IMPACT OF INDIVIDUAL PWEC ASSETS

	2003 ENERGY LEVELS							2002 ENERGY LEVELS				
BASE FUEL AND PURCHASED POWER EXPENSE	FUEL/PURCH PWR COST ($000)		NATIVE LOAD SALES (MWH)		AVERAGE COST ($/MWH)		RETAIL SALES (MWH)		FUEL/PURCH PWR COST ($000)	CHANGE FROM PREVIOUS CASE ($000)	CUMULATIVE CHANGE ($000)
APS W/O PWEC ASSETS	584,086	÷	25,208,287	=	23.17	×	23,473,646	=	543,894	-	-
ADD REDHAWK											
TRACK B CONTRACTS TERMINATED	594,872	÷	25,208,287	=	23.60	×	23,473,646	=	553,937	10,044	10,044
REDHAWK INCLUDED IN DISPATCH	545,992	÷	25,208,287	=	21.66	×	23,473,646	=	508,421	(45,516)	(35,473)
ADD WEST PHOENIX CC5	544,962	÷	25,208,287	=	21.62	×	23,473,646	=	507,462	(959)	(36,432)
ADD WEST PHOENIX CC4	546,548	÷	25,208,287	=	21.68	×	23,473,646	=	508,939	1,477	(34,955)
ADD SAGUARO CT3 ALL PWEC ASSETS INCLUDED	546,522	÷	25,208,287	=	21.68	×	23,473,646	=	508,915	(24)	(34,979)

OFF-SYSTEM SALES MARGIN CREDIT TO EXPENSE	OFF-SYSTEM MARGIN ($000)	CHANGE FROM PREVIOUS CASE ($000)	CUMULATIVE CHANGE ($000)
APS W/O PWEC ASSETS	(14,749)	-	-
ADD REDHAWK			
TRACK B CONTRACTS TERMINATED	(5,172)	9,577	9,577
REDHAWK INCLUDED IN DISPATCH	(26,066)	(20,894)	(11,317)
ADD WEST PHOENIX CC5	(40,198)	(14,132)	(25,449)
ADD WEST PHOENIX CC4	(44,981)	(4,783)	(30,232)
ADD SAGUARO CT3 ALL PWEC ASSETS INCLUDED	(46,411)	(1,430)	(31,662)

ATTACHMENT PME-18RB

OPERATING REVENUE LESS FUEL AND PURCHASED POWER EXPENSE
IMPACT OF INDIVIDUAL PWEC ASSETS

TOTAL COMPANY NET SYSTEM COST	FUEL/PURCH PWR NET SYSTEM COST ($000)	CHANGE FROM PREVIOUS CASE ($000)	CUMULATIVE CHANGE ($000)
1. APS W/O PWEC ASSETS	529,145	-	-
2. ADD REDHAWK			
a. TRACK B CONTRACTS TERMINATED	548,765	19,621	19,621
b. REDHAWK INCLUDED IN DISPATCH	482,355	(66,410)	(46,790)
3. ADD WEST PHOENIX CC5	467,264	(15,091)	(61,881)
4. ADD WEST PHOENIX CC4	463,958	(3,306)	(65,187)
5. ADD SAGUARO CT3 ALL PWEC ASSETS INCLUDED	462,504	(1,454)	(66,641)

APS-12R

EXHIBIT
APS-12R
admitted

REBUTTAL TESTIMONY OF THOMAS A. HINES

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

Table of Contents

REBUTTAL TESTIMONY OF THOMAS A. HINES ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY (DOCKET NO. E-01345A-03-0437)

I. <u>INTRODUCTION</u>.

Q. PLEASE STATE YOUR NAME.

A. Thomas A. Hines.

Q. WHAT IS YOUR POSITION AND WHAT ARE YOUR RESPONSIBILITIES AT APS?

A. I am Program Manager of Energy Efficiency and Market Transformation Programs. In that capacity, I develop and implement current APS market transformation and demand side management ("DSM") programs, including residential new construction, residential HVAC retrofits, commercial pilot programs, and related consumer energy efficiency education efforts. This includes research and development, evaluation, analysis and planning for new DSM programs and energy efficiency/market transformation opportunities. A Statement of Qualifications is attached to my rebuttal testimony as Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to certain recommendations made by intervenors in this proceeding concerning DSM programs. I will provide additional detail and technical background for the DSM issues to support the rebuttal testimony of APS witness Edward Z. Fox, who discusses DSM policy issues. I will also respond to several of the questions posed in Commissioner Hatch-Miller's November 17, 2003 letter concerning DSM programs. Commissioner Hatch-Miller asked for information about DSM programs in nearby states, and whether APS could expand its current DSM efforts.

II. SUMMARY OF TESTIMONY.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

As Mr. Fox discusses in his rebuttal testimony, APS believes that a reasonably expanded DSM program can provide customer benefits and help the Company cost-effectively manage both overall customer growth and growth in peak demand. The Company is proposing an expanded DSM program which is expected to achieve on average approximately 45 MWs of incremental peak reduction and 100,000 MWhs of incremental energy reduction per year. Thus, by 2010 the expanded DSM program is projected to achieve a reduction of the 2010 system peak of 270 MWs, which is a 3.4% reduction, and a reduction of 600,000 MWHs in 2010, which is 1.7% of total retail energy. These results are in addition to the current results of our market transformation programs, which have been in place since 1997. The total impact of both current (since 1997) and proposed market transformation programs would be a 6% reduction in peak and 2.3% reduction in energy usage in 2010. The total proposed funding for the expanded DSM/market transformation program would be $3 million per year, which is roughly triple the current funding level.APS' DSM proposal is generally consistent with Staff's DSM proposal as outlined in the testimony of Staff Witness Barbara Keene. Furthermore, the recommended level of spending in Ms. Keene's testimony is generally in line with the level that APS believes would be appropriate. (B. Keene Testimony at p.10). The key disagreement between APS and both the Residential Utility Consumer Office ("RUCO") and Southwest Energy Efficiency Project ("SWEEP") is the proposed level of cost-effective DSM and the associated DSM spending. Both RUCO and SWEEP propose spending on average over $30 million per year compared to the $3 million to $4 million proposed by the Company and Staff, respectively. APS does not believe that either RUCO or SWEEP offer enough compelling evidence to support their proposal for such an extreme increase in DSM, which is many times more than any historic level in the state.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I will discuss APS' current DSM programs, which emphasizes the market transformation approach. Second, I will cover several rebuttal issues, especially the program recommendations of SWEEP and RUCO, and several DSM-related issues raised by Staff. Lastly, I will address several questions posed by Commissioner Hatch-Miller in his letter concerning certain DSM issues.

III. <u>APS' CURRENT AND PROPOSED DSM PROGRAMS</u>

Q. PLEASE DESCRIBE GENERALLY THE DSM PROGRAMS THAT THE COMPANY IS CURRENTLY IMPLEMENTING?

A. APS currently offers DSM programs focused on energy efficient residential new construction, efficient air conditioning in existing homes, low income weatherization, as well as extensive ongoing customer education efforts. APS' Energy Wise Low Income Weatherization Program is designed to improve the energy efficiency and safety attributes of homes for customers whose income falls within federal poverty guidelines. In the 2002 test year, this program served 833 low income customers with various home improvements including cooling system repair and replacement, insulation, sunscreens, water heaters, window repairs and improvements as well as other general repairs. The program is administered through a variety of community action agencies throughout APS' service territory.

For existing homes, APS promotes HVAC tune-up and replacement by a "Qualified Contractor." Using contractors who meet strict program training requirements, this program has produced over 13,000 customer referrals for heating/cooling system tune-ups, upgrades and replacements (including 4,100 referrals in the test year). In new home construction, APS offers the Performance Built Home program. This program promotes builders who offer homebuyers guaranteed heating and cooling costs. Largely as a result of this program, Arizona is a national leader in the number of housing starts offering guaranteed heating and cooling costs. SWEEP confirms this achievement reporting that Arizona accounted for about 20% of all Energy star homes in the nation as of 2001 (Mother Lode Report at 5). Since the implementation of APS' program in 2001, five of the top ten Phoenix area builders have participated, with over 2,500 homes constructed and over 10,000 homes committed to the program to date.

To help residential customers manage energy costs and limit peak demand, APS has two successful and effective time-of-use pricing plans (Time Advantage and Combined Advantage). Although both plans have time differentiated energy charges, the Combined Advantage plan also adds a peak demand charge component for an additional incentive to shift load to off peak periods. Customers who are willing to limit their on-peak energy use can take advantage of lower off-peak prices to save on their energy costs. On average, for 2003, APS had nearly 330,000 residential time-of-use customers, which was roughly 40% of all residential customers. This is one of the highest participation rates of any time-of-use program in the United States. APS provides education for time-of-use customers to help them learn how to shift their energy consumption to best take advantage of their pricing plan. Although in the past some parties have separated the consideration of time-of-use prices from DSM, we believe that this separation is artificial and not appropriate at this time. In fact, price signals and demand response should be an important and integral part of an overall DSM/market transformation plan. After all, prices are a key factor in stimulating energy efficiency and in determining the benefits of efficiency investments from the customer's point of view. Proper price signals can also be one of the most effective tools for managing peak demand, as evidenced by recent industry trends to integrate time differentiated pricing into DSM strategies and demand response initiatives.[1] Furthermore, we expect that as more customers participate in time-of-use rates the program costs necessary to implement DSM should decrease. Therefore, we are including the peak and energy impacts and promotional costs of time-of-use rates in our DSM/market transformation plan.

APS has also helped to improve "real world" efficiency of new and existing homes using building science and extensive training for builders, insulation installers and the HVAC contractor trade to improve the performance of measures taken to increase energy efficiency. For example, APS-sponsored building science training sessions have been attended by all of the top ten builders in Phoenix with over 1,500 construction industry personnel attending. APS supports annual HVAC training resulting in 500 service technicians trained each year, a total of over 2,500 since the program was instituted. Also, APS has produced extensive consumer educational materials including on-line resources, consumer guides, energy end-use fact sheets, newspaper articles and supplements, seminars, new home point-of-sale materials, and an energy answer phone line.

In addition, the Company is currently conducting pilots of two small scale commercial DSM programs, which include a voluntary peak reduction program and a building operator and facility manager training program. All of these programs are focused on market transformation as opposed to traditional rebate programs. Time-of–use rates are also important for leveraging DSM spending for

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[1] See for example, New England Demand Response Initiative stakeholder meeting presentations on pricing

commercial customers. For example, commercial design assistance can help identify opportunities upfront to shed load for peak demand response in conjunction with time-differentiated rates.

In each of these programs, APS has effectively leveraged resources by partnering with government and industry groups including the Arizona Energy Office, Electric League of Arizona, Arizona Heat Pump Council, City of Scottsdale Green Building Program, Energy and Environmental Building Association, Advanced Energy, EPA/DOE, Arizona Department of Environmental Quality, Homebuilder's Association of Central Arizona, Arizona School of Real Estate, Arizona Energy Management Council, Arizona Masonry Guild, contractors, builders, product manufacturers and others. Such leveraging has reduced APS' cost of DSM programs while helping to build relationships and strengthen energy efficiency messages.

Q. WHAT IS MEANT BY A "MARKET TRANSFORMATION" APPROACH AND WHAT ARE THE BENEFITS ASSOCIATED WITH THIS APPROACH?

A. Market transformation programs focus on education, training and public information to promote a lasting shift in the market for energy efficient products and services. The concept is to identify key participants and understand their behavior and points of decision concerning energy efficiency, and to influence these decisions and behaviors in a manner that can persist. This requires direct involvement with builders, contractors, energy managers, customers and other key participants.

The benefits of this approach are three-fold. First, as I just mentioned, market transformation can provide a more lasting improvement to energy efficiency

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and metering January 15, 2003 and February 10, 2003.

because you are changing attitudes and behavior, and increasing knowledge about energy efficiency. For example, if you merely give a customer a rebate for efficient lighting you can achieve quick results, but the results will not last if the customer returns to standard lighting once the efficient lamps burn out. In this example, you have not effectively changed the attitudes, knowledge, or behavior of the customer or of the lighting contractor that is making recommendations to the customer. On the other hand, the market transformation approach focuses on getting the customer to understand why it is beneficial for them to purchase energy efficiency products.

The second benefit of a market transformation approach is that it can be much more cost effective than other DSM strategies in the long run. For example, many efficiency practices do not require a significant investment on the part of customers, builders or contractors. Instead, they require a change in behavior—in construction practices, installation methods, and proper operation and maintenance of equipment.

A quick example may help illustrate how a market transformation approach can reduce costs and limit free riders. In the new construction market, APS has used extensive builder/contractor training and consumer education to drive lasting changes in building practices. By educating builders and consumers how they can enhance profits and save money by choosing energy efficient construction practices, APS has begun to significantly transform this market and instill ongoing energy efficiency awareness, attitudes and choices. Through 2003, over 10,000 energy efficient homes have been built or committed to be built as part of the program for a total program cost of approximately $600,000.

Now assume that APS instead chose a rebate approach to incent builders to construct energy efficient homes. Assuming a typical range for rebates of $250-$300 per home, incentive costs alone for the 10,000 homes committed to the program to date would have been $2.5 to $3 million (exclusive of program marketing and administrative costs). By taking a market transformation approach, greater efficiency has been achieved for less than one-fourth the cost. In contrast, if rebates were provided to encourage behavior, costs would be significantly higher and results may not be as long lasting once the rebates are removed. Furthermore, presumably some of the builders would have constructed energy efficient homes absent the program, but gladly collect the rebate anyway. These "free riders" would further degrade the cost-effectiveness of the program, beyond the example given. The market transformation approach can significantly limit free riders because there is no "easy money" to be obtained and the Company is more involved with the program participant (in this case the builder) and thus we can better identify baseline levels of behavior.

For APS' programs that address these issues, such as our residential construction and HVAC programs, the Company focuses on training builders and contractors, educating customers, conducting site inspections and on-the-job training to field-test the actual performance of the efficiency improvements and to ensure that the improved construction and installation practices are being properly implemented. Field testing includes high-tech equipment such as blower doors, duct blasters, flow hoods and infrared cameras to provide immediate feedback for builders on the performance of their homes. APS also includes site inspections to ensure that the improved construction and installation practices are being properly implemented. This effort requires some program costs on our part, but because the incremental costs to the builder or contractor are relatively small, we do not have to spend program dollars to overcome this potential hurdle. The key point of APS' involvement is to help consumers and industry trade allies understand the value of a particular energy efficiency measure and how to achieve it. Once this value is accepted in the market, this approach can result in persistent improvements in energy efficiency that remain in place over time without significant additional utility expenditures.

Finally, we have found that for many efficiency improvements proper installation, operation and maintenance are more critical than the equipment itself. For example, in a recent national study[2] the field-tested efficiency of 12 SEER air conditioners and heat pumps was less than 7 SEER in actual performance due to installation problems including duct leakage, improper system airflow and refrigerant charge, and equipment over-sizing. Again, if APS only gives a rebate for an efficient air conditioning unit, the actual efficiency improvement could be much different than the expectation if the equipment is improperly installed. A market transformation approach that addresses these issues can ensure that the expected efficiency is actually being achieved.

Q. HAS THE COMPANY IMPLEMENTED ITS DSM PROGRAMS AS DIRECTED BY THE COMMISSION?

A. Yes. Prior to 1997, APS used rebates extensively to subsidize the incremental upfront cost to the customer of energy efficiency equipment. However, the desire to move away from costly rebate programs prompted the Commission and APS to look for innovative market transformation approaches to achieve more long-term benefits (Decision 59601 at 7). Thus, in 1996, under the Commission's direction,

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2 Neal, C Leon, P.E "Field Adjusted SEER (SEERFA)– Residential Buildings: Technologies, Design and Performance Analysis." Proceedings of 1998 ACEEE Summer Study on Energy Efficiency in Buildings, Vol. 1, pg 1.197-1.209.

APS ended the last of its incentive-based DSM programs and transitioned to market transformation-based DSM programs.

Q. DO YOU BELIEVE THAT THE COMPANY'S CURRENT DSM PROGRAMS ARE ACCOMPLISHING THE MARKET TRANSFORMATION OBJECTIVES SET FORTH BY THE COMMISSION?

A. Yes. The current market transformation programs have been very successful. APS estimates that the current DSM and market transformation program from 1997 to 2004 has resulted in a projected reduction in the 2004 system peak demand of approximately 205 MW and 230,000 MWh of energy reduction in 2004. The total energy savings over this period was over 1.8 million Mwh. And if you consider the entire impact of APS' DSM and market transformation programs from 1992 to 2004, we project to achieve approximately 352 MWs of peak demand savings and 348,000 Mwh of annual energy savings in 2004. The total energy reduction for the entire period 1992 to 2004 is over 2.2 million MWh. In addition, education has also undoubtedly helped countless customers save additional energy costs, however, these savings are difficult to quantify.

Although APS provides energy efficiency information on numerous topics, the Company has focused on providing information on how to reduce the cost for space heating and cooling, because these costs represent nearly 50% of annual energy bills for residential customers. Therefore, over the past seven years, APS has helped to significantly transform current residential construction and HVAC installation practices. For example, APS has achieved a significant penetration into the residential building and HVAC retrofit markets with both major builders and HVAC contractors participating in the programs. Many homes and HVAC systems incorporate recommended energy efficiency improvements that are, most importantly, installed correctly. These improvements come at low additional costs to builders, contractors, and customers; they are merely better building and installation practices that produce increased efficiency results. Further, our training, education, monitoring, and ongoing involvement with builders and HVAC contractors help make these practices part of their normal business routine, which can produce lasting improvements. The goal is to help customers use our product more efficiently. By providing ways for customers to save on their energy costs, APS' current programs support this goal.

Q. WHAT DOES THE COMPANY PROPOSE FOR AN EXPANDED DSM PROGRAM?

A. Contingent on Commission approval and funding, APS proposes to expand our current proven DSM programs as well as implement new programs, especially for commercial customers. In general, we will continue to focus on programs that can help us manage our growth, especially during peak periods of electrical use. APS also proposes to continue to adhere to the market transformation approach for both existing and new programs which has produced the benefits discussed above. Although we intend to present more specific information in the Commission's ongoing DSM workshops, I will outline the Company's general proposals by customer class.

Q. PLEASE EXPLAIN WHAT YOU WOULD PROPOSE FOR RESIDENTIAL CUSTOMERS.

A. For residential customers, APS would expand both of our existing programs—the new construction program and the "Qualified Contractor" retrofit air conditioning program. Both of these programs are successful, but increased funding can extend the program to additional builders, contractors, and customers. For our residential new construction program, the Company would continue to emphasize the key energy efficiency practices including the quality of insulation installation, air balancing, installing energy efficient low emissivity (low E) windows, proper duct installation and sealing, sealing the perimeter envelope of the home, and HVAC equipment, installation and sizing. APS would also provide additional promotion for "Performance Built Homes" and increase our focus on building science training for builders, contractors, and realtors.

To enhance the programs targeted towards existing residential homes, APS would conduct a new educational campaign to support the retrofit air conditioning program and also begin to promote 14 SEER air conditioning equipment due to the ongoing decreases in incremental equipment cost and the expected increase in minimum federal standards for air conditioner efficiencies. We anticipate that the new federal minimum standard will be increased to 12 or 13 SEER in 2006. In addition, 14 SEER equipment employs the variable-speed fan technology mentioned by SWEEP, which will provide additional savings and other benefits for customers.

APS would also increase the development and promotion of home performance testing, enhance support for the Energy Management Council and their program to train and certify HVAC contractors in building science principles and home performance testing techniques, and work with contractors to promote and offer discounts for "Home Comfort/Performance" tests. This type of discount program is an excellent example of a very cost-effective way to use market cooperation to "simulate" old utility rebate programs. In exchange for utility promotion, participating contractors offer a discounted special promotional rate for APS customers. To the customer who receives a discount, it is just as valuable as a rebate, yet it comes at no cost to our customers. Since 2000, APS has used this approach to promote low-cost HVAC tune-ups through a cooperative advertising program with participating qualified contractors.

In addition, APS would implement an educational campaign to support programs and to provide general information on home energy efficiency do-it-yourself Web-based home energy audits, information on efficient appliances, lighting, HVAC, and other related issues. APS also proposes to translate these communications for our Spanish speaking customers.

Following the example of some of the programs in other western states, APS would also consider a pilot program for residential direct load control. APS would examine new technology, assess potential customer acceptance in our extreme summer climate, and estimate achievable peak demand reductions from this program. Also, like other western states, APS would conduct targeted education to help existing time-of-use customers learn how to shift energy use and take better advantage of time-of-use pricing signals to get the most value from the rate.

Q. TO IMPLEMENT THESE PROGRAMS, HOW MUCH DSM FUNDING WOULD BE REQUIRED?

A. APS could implement these expanded existing and new residential programs discussed above for roughly $1.3 million total spending per year.

Q. WOULD YOU ALSO INCLUDE CHANGES FOR THE LOW INCOME WEATHERIZATION PROGRAM?

A. Yes. The Company is proposing several changes to the low income weatherization program which will help to address some of the implementation issues discussed by Mr. Fox. These changes would also accommodate increased spending above past levels. First, APS would continue to work with the agencies that implement this program to be able to accommodate an increased level of targeted homes per year. Second, APS would propose to increase the maximum funding limit per household, which will enable more flexibility for implementing repairs and efficiency improvements, especially for replacing or repairing HVAC equipment.

Third, in an effort to extend the program to more customers, especially the "working poor", we propose to raise minimum income requirements for the program to allow us to serve more customers who are close to poverty level but not currently eligible. Such a change is consistent with recent trends for weatherization programs in several other states. Finally, APS would loosen current restrictions that only allow customers in owner-occupied housing to participate, and extend the program to renters. These changes will provide additional flexibility to the program which will increase benefits to low income customers and accommodate increased spending above past levels. To implement all of these changes would increase the funding level to approximately $700,000 per year.

Q. PLEASE DESCRIBE YOUR PLANS FOR COMMERCIAL, INDUSTRIAL AND INSTITUTIONAL SEGMENTS.

A. The Company proposes to expand the two current commercial pilot programs— the Power Partners voluntary peak reduction program and the facility manager training program, which is designed to help facility managers and building operators better control their energy costs. In addition, APS proposes to offer several new programs for commercial, industrial, and institutional customers. First, APS would develop a program to provide better and more timely information concerning energy usage to energy mangers. This Energy Profile and Demand Response program will provide Web-based, real-time load profile information and feedback to help managers understand where and how they use energy, which in turn will help them reduce their peak demand and energy usage or shift usage to off-peak periods. This real-time information and related communication infrastructure can also support demand response programs or curtailment programs, which we may wish to implement in the future. This program would be targeted to large commercial, industrial and institutional customers with over 1 MW of peak demand.

Next, APS would implement a commercial cool roofs program which will promote the use of cool roofing materials for new and re-roofing applications through training and cooperative promotion with commercial roofing companies. We would use the Arizona Roofing Council trade association to help implement the program. Our initial investigation suggests that cool roofs can save up to 3% of total energy costs for commercial buildings, and it also reduces energy consumption during peak periods.

APS would also offer a design assistance program for new commercial buildings and extensive remodels. The program would focus on large projects and offer building science design seminars and customized energy simulations with recommended efficiency upgrades. To implement the program APS would partner with the Energy Office of the Arizona Department of Commerce, Arizona State University, and the Leadership in Energy and Environmental Design (LEEDS) U.S. Green Building Council certification program.

Finally, APS would develop a demonstration program offering grants to schools to implement efficiency improvements and help them reduce their energy costs. This program is very timely in light of expected changes to the energy budgets for Arizona school districts. For this program, APS would partner with existing programs at Arizona State University and the Arizona Energy Office which address energy efficiency in schools and provide grants to fund energy efficiency demonstration projects in schools. APS will also seek to partner with existing successful Arizona Energy Office programs, such as the Municipal Energy Management Program (MEMP), which provides grants to Arizona cities and towns to help them manage energy costs. This successful program faces funding shortages and may need additional funds to continue.

Q. HOW MUCH FUNDING WOULD BE NEEDED FOR THESE EXPANDED COMMERCIAL, INDUSTRIAL AND INSTITUTIONAL DSM PROGRAMS?

A. Roughly $1 million per year.

Q. HOW MUCH TOTAL DSM FUNDING IS NECESSARY FOR ALL OF THESE DSM PROGRAMS?

A. All these DSM programs would require about $3 million per year to implement, which is about three times our current level of DSM spending.

Q. WHAT DO YOU EXPECT TO ACHIEVE FROM THIS EXPANDED DSM PROGRAM PORTFOLIO?

A. First of all, this level of increased DSM funding would provide opportunities for all customer segments to participate in some form of DSM activities, if they desire. The proposed spending level strikes a balance between achieving very significant DSM results at a reasonable cost. By effectively leveraging utility dollars through partnerships, avoiding costly rebates, and taking advantage of the momentum in our current market transformation programs, APS can achieve significant results in a very cost-effective manner. We believe that our proposed expanded DSM program can achieve a substantial portion of SWEEP' projected energy savings at a significantly lower cost. APS estimates that its proposed programs can achieve nearly 50% of SWEEP's proposed demand and 25% of their proposed energy savings with about 10% of the proposed funding.

Based on current program plans and projections, the Company estimates that the proposed DSM program portfolio I discussed could achieve on average almost 45 MW of incremental peak demand reduction per year and approximately 100,000 MWH of incremental energy savings each year. Thus, assuming the expanded program begins in 2005 it is expected to achieve roughly 270 MWs of additional reductions in the 2010 peak and 600,000 MWh additional energy savings in 2010, which are the savings referenced above in relation to the SWEEP proposal. However, these savings would be in addition to the past program results achieved prior to 2005 as summarized earlier in my testimony. Therefore, the total impact of current and proposed market transformation programs since 1997 would be a 6% reduction in peak and 2.3% reduction in overall energy usage in 2010. Furthermore, this achievement does not include the significant energy savings that have resulted from APS' general energy efficiency education efforts, which are difficult to quantify.

Q. WHY HAS THE COMPANY EMPHASIZED PEAK REDUCTION IN BOTH ITS CURRENT AND PROPOSED DSM/MT PROGRAMS?

A. While our programs have achieved, and will continue to achieve, reductions in both peak demand and energy, the company has recognized the important benefit that DSM can provide in helping to manage our growth in system peak demand and reducing usage during peak periods. Indeed, one of the key drivers for optimizing the cost effectiveness of DSM programs, aside from keeping program costs low as previously discussed, is the reduction in generation and fuel costs resulting from peak load reductions. It is probably no surprise that APS' system is heavily summer peaking. In fact, our summer peak usage is typically over twice as large as the peak usage in November or March. Furthermore, our incremental capacity costs are planned to cover our system peak and fuel expenses, which are typically much higher during summer peak periods versus night-time or non-summer periods. The upshot is that DSM programs that primarily reduce energy usage during off-peak periods are of much lower value to the Company. In addition, as more and more customers participate in time-of-use rates, DSM programs that emphasize these off-peak oriented measures would also be of lower value to the customer.

IV. STAFF AND INTERVENOR DSM TESTIMONY.

Q. WHAT ARE THE KEY AREAS OF AGREEMENT AND DISAGREEMENT WITH THE PARTIES' DSM RECOMMENDATIONS IN THIS CASE?

A. APS generally agrees with Staff's DSM proposal and the recommended level of spending in Ms. Keene's testimony, which is generally in line with APS' proposed expansion of DSM programs and the associated spending level that APS believes is appropriate. (B. Keene Testimony at p.10). The key disagreement between APS and both RUCO and SWEEP is the proposed level of cost-effective DSM and the associated DSM spending. Both RUCO and SWEEP propose spending on average over $30 million per year compared to the $3 million to $4 million proposed by the Company and Staff, respectively. Additionally, SWEEP's proposed goals for reducing future peak and energy consumption through DSM are not supported by enough relevant information, and have not demonstrated sufficient customer benefits to warrant the level of increased spending recommended. We believe that SWEEP has also overstated both the baseline level of energy efficiency in Arizona as well as the overall potential for DSM applicable to the Company.

APS recognizes that some of SWEEP's program ideas and implementation strategies for expanding DSM merit further consideration. For example, design assistance for commercial construction, school programs, residential new construction, low income programs, and residential heating and cooling programs discussed by SWEEP are being considered in APS' proposed DSM program portfolio (Schlegel at 11). We agree with SWEEP that APS has "a beneficial residential new construction program that is achieving meaningful results," (Schlegel at 3) and that DSM programs should be extended to other customer segments, such as commercial customers (Schlegel at 11). We agree that the "energy efficiency programs should be market-oriented, thereby leveraging and focusing on naturally-occurring market opportunities"(Schlegel at 11). Also, the Company is in general agreement with SWEEP that any DSM programs approved should provide both peak demand and energy savings (Schlegel at 11), but APS believes that it is more appropriate to put a greater emphasis on peak savings due to its objective to use DSM to help manage peak growth.

Q. COULD YOU RESPOND IN MORE DETAIL TO APS' CONCERNS WITH SWEEP'S PROPOSAL?

A. Yes. I believe that SWEEP distorts the baseline level of energy efficiency in Arizona by making inaccurate comparisons between Arizona and other states. For example, SWEEP claims that Arizona is ranked 45th among states in energy efficiency savings. (Schlegel at 6). However, the report SWEEP cites is not accurate for a number of reasons. On page 2 of the American Council for an Energy Efficient Economy ("ACEEE") report that SWEEP cites, the authors list a number of major issues with their data, including:

> A major caveat of the data and resulting reporting and ranking by state energy efficiency activity is that the EIA data (on which the report is based) is self-reported and not independently verified as to accuracy. Not all utilities report these DSM data to EIA and those that do may use different methods to estimate savings data. Consequently, the EIA data is somewhat incomplete, and data from utility to utility may not be exactly comparable.

The authors continue to list many other concerns, including differences in how public benefit spending is classified in each state and the fact that many utilities serve multiple states, making it difficult to allocate spending for each state. Additionally, the authors caution that their state level analysis can be misleading when looking at individual utilities within a state, because there can be substantial variations from utility to utility in a state, and strong utility programs may be diluted when programs are viewed statewide. Finally, the authors state that they, "Place greater confidence in the accuracy of reported energy efficiency expenditures than savings values" because they believe that data on utility DSM expenditures are more accurate and less prone to variation than utility reported DSM savings data.

The ACEEE report relies only on self-reported DSM savings to the EIA; however, APS did not report DSM savings to the EIA for the year in question (2000). Therefore, the report findings are particularly inaccurate for Arizona, and significantly understate the current level of energy savings in the state. The authors did not attempt to contact APS for additional information to determine current energy savings when they compiled the report. As part of the ongoing DSM workshops, APS has provided estimated incremental energy savings for the year in question (2000) of approximately 24 MW and 26,000 MWh. In addition our total energy savings in 2000 was 238 MW and 207,000 MWH. If this information were included in the ACEEE report, it is clear that Arizona's state ranking would be significantly higher.

Using the same information that SWEEP cites (Schlegel at 5, ACEEE), there are only a few states that have maintained the large old-style DSM programs that the Commission abandoned years ago. In fact, according to the ACEEE, "About one-third of the states (16 states) account for 86% of total US spending on energy efficiency programs." (ACEEE, pg iv). These are typically states with very high electric rates in the Northeast or California, as well as states with particular resource constraints. Further, some of the states cited in the report, such as Massachusetts, Rhode Island and Connecticut, have very cold climates so the results do not directly compare with Arizona. As I will discuss below, some states in the West, most notably Nevada, have recently implemented expanded DSM programs. However, their programs were driven by escalating energy supply costs due to an unhedged over reliance on the wholesale market, which is not currently the case for APS. The majority of states (34) spend only a fraction of the extreme examples that SWEEP cites.

In Arizona, APS has effectively managed supply resources and current market transformation programs are already achieving significant energy savings. Therefore, the aggressive level of DSM spending proposed by RUCO and SWEEP is simply not warranted for Arizona.

Q. ARE THERE OTHER DEFICIENCIES IN SWEEP'S ANALYSIS OF HOW DSM PROGRAMS MIGHT BENEFIT APS?

A. Yes. SWEEP also misinterprets the cause and nature of load growth in Arizona. They imply that APS' peak growth is driven by energy inefficiency, asserting that "each day that passes without effective energy efficiency programs means more inefficient load is added to the system" (Schlegel at 3). While DSM can help manage peak growth, the cause of the increased load growth that we are experiencing is not driven by energy inefficiency. New homes, air conditioners, windows, and appliances are all much more efficient compared to past levels. Population and economic growth, customer preference for larger homes, and increased plug loads including, for example, big screen TVs, home entertainment systems, numerous new appliances, and computers are driving APS' load growth. For example, the average size of all residential homes (single family detached) in APS' "desert area", which includes the Phoenix metro area, has grown by 11% over the last 10 years, which is the largest single driver for the 12% growth in average energy usage per customer, normalized for weather, over this same period.

Furthermore, virtually none of these factors can be controlled by utility DSM programs. APS cannot prevent people from moving to Arizona, nor dictate that people live in smaller homes. Frankly many of the new plug loads are already energy efficient. In fact, we believe that the results of our current energy efficiency programs, especially increased efficiency of new homes, replacement HVAC systems and replacement appliances, have significantly helped in moderating the impact of high growth rates in APS' service territory.

Q. DOES SWEEP OVERSTATE THE POTENTIAL FOR ENERGY EFFICIENCY GAINS AND THE COSTS OF THEIR PROPOSED PROGRAMS?

A. I believe so. Similar to the misinterpretation of the cause and nature of load growth for APS, SWEEP has also overstated the potential for improving the energy efficiency in APS' service territory, especially in the context of utility DSM programs (Schlegel at 4). APS has a number of concerns with SWEEP's analysis of energy efficiency potential in Arizona, including SWEEP's inaccurate characterization of current baseline conditions, their calculation of achievable savings per measure, their assumptions about achievable market penetration, their lack of specific cost data, and reliance on questionable technologies.

First, some of the estimates of potential energy savings provided in SWEEP's testimony and supporting documents appear to compute potential energy savings by comparing the efficiency of a new appliance or other DSM measure with the efficiency of an existing appliance that is being replaced. This assumes that every appliance is replaced as a result of the DSM program. This is an incorrect assumption which greatly exaggerates the potential savings. Energy savings should be derived by comparing the efficiency of the new appliance with an alternate new appliance that would likely be purchased absent the DSM program. For example, air conditioner efficiencies have increased significantly over the past

20 years, from a rating of 6 SEER (seasonal energy efficiency ratio) twenty years ago to a minimum of 10 SEER today, which is a federal standard. If a customer's 20 year-old air conditioner needs replacing, a utility's DSM program may influence them to purchase a more efficient 12 SEER unit instead of the standard 10 SEER unit. In this case, the correct estimate of energy savings from the DSM program would be to compare the efficiency of the 12 SEER unit with the less efficient 10 SEER unit that would have been purchased without the program. However, it would be incorrect to estimate energy savings by comparing the 12 SEER unit with the 6 SEER unit being replaced, which is SWEEP's approach to calculating energy savings.

For example, on page A-20 of the Mother Lode Report, SWEEP claims a 28% savings for 13 SEER replacement residential air conditioners. Air conditioning contractors tell APS that 90% of replacement air conditioners are 12 SEER or higher. The savings due to upgrading from the de facto standard of 12 SEER in APS service areas to 13 SEER is less than 8%. Moving the market to 13 SEER will save 8%, not 28%.

In addition, SWEEP's assumed baseline efficiency levels often indicate the use of old appliance efficiencies to calculate energy savings. As a result, the per-unit energy savings for many of these measures are overstated. For example, in the commercial segment, SWEEP's Existing Medium Office program, which promotes efficient Energy Star equipment, claims a 15% savings. However, according to Energy Star information, 90% of new office equipment is already Energy Star compliant, so the actual "effective" savings from this program would be minimal.

In the existing-homes residential segment, SWEEP chose to arbitrarily inflate current electricity use by 10%, due to their rationale that energy use is increasing, which is another example of an inaccurate assumption that results in inflated savings potential.

Another significant deficiency in SWEEP's analysis is that some of the potential savings estimates are based on DSM measures that are not technically feasible, or would have low customer acceptance, or do not perform as expected in real world installations. For example, the technical feasibility of retrofitting air conditioners with ECM, or multi-speed fans, which is one of SWEEP's recommended programs (SWEEP Mother Lode report, p. A-20), is highly questionable. While multi-speed fan motors are being used effectively in new high-SEER air conditioning equipment, retrofitting this technology to old existing equipment is not a proven concept at this time. Recent consultations with an HVAC manufacturer and several air conditioning contractors confirm that it is not practical to retrofit these motors to existing equipment. Similarly, an example of a program that we believe would have low potential customer acceptance is SWEEP's white roof program for residential homes. We expect that white roofs would probably not be aesthetically acceptable to many homeowners or homeowners' associations in the Phoenix metro area. While this program could be acceptable for a small number of flat roofed homes (many of which already use cool color materials), the overall market penetration would be very low. An example of a DSM measure that probably would not perform as expected in real world installations is SWEEP's programmable thermostat program. There is significant evidence in the industry asserting that energy savings from programmable thermostats are very limited in actual installations due to customer behavior in resetting these thermostats (e.g. November 2000 issue of Energy Design Update).

Finally, although SWEEP makes broad statements about the general costs of DSM programs, the actual cost estimates of individual DSM programs proposed by SWEEP do not withstand close scrutiny and are likely understated. For example, SWEEP confirms that their backup documents contain a mathematical error in computing the incremental measure cost per square foot. As a result, SWEEP's reported values for the cost per square foot for implementing efficiency measures are about 10% of the actual costs (Mother Lode Report tables pages A-20 through A-27). In addition, in its analysis of the Mother Lode report, APS could not find any information concerning program administrative or marketing costs, so it is unclear whether these costs were included in their cost effectiveness evaluations. SWEEP also makes extremely aggressive assumptions about the expected market penetration that can be achieved for each DSM measure, with little evidence to support these assumptions.

While none of these issues mean that every program proposed by SWEEP should be rejected out of hand, it does mean that a more careful and more reasonable approach to implementing an expanded DSM program is more appropriate than the proposals of either SWEEP or RUCO.

Q. DO YOU AGREE WITH STAFF'S PROPOSAL CONCERNING COST-EFFECTIVENESS?

A. Certainly cost-effectiveness is a key benchmark when measuring potential DSM programs. The Company would continue to implement cost-effective DSM programs and to screen new programs for costs and benefits through Staff's pre-approval process. However, Ms. Keene has proposed that the Company should implement programs where the "incremental societal benefits...are greater than the incremental cost of those programs to society." The "societal cost test" proposed by Ms. Keene (Keene at 2-3) has significant limitations that make it inappropriate to use in today's environment.

Specifically, the societal cost test compares the resources required for DSM investments versus the resources required for generation supply alternatives. The idea is that society can either invest money to reduce the electrical load or invest money to serve that load through utility generation. For DSM, these resources would include the utility program costs as well as any other associated costs incurred by program participants, contractors, vendors, or other parties involved in the program. On the other hand the costs to serve the load would include generation—capacity and fuel costs—and any other avoided utility costs created by the DSM program. In theory, the social costs could also include positive or negative externalities such as pollution or impacts on jobs or economic development. Further, the societal cost test would exclude any impacts that do not affect resources, but merely transfer costs or benefits from one party to another. For, example the societal test would ignore any potential rate impacts caused by DSM spending. Such impacts would be viewed as merely transferring costs from program participants to non-participants.

Although the Commission adopted a societal cost test in the integrated resource planning era—a practice which was suspended in 1997 [Decision 60385 (August 29, 1997)]—it recognized two important shortcomings of the test [See Decision 57589 (October 29, 1991) at 10; Decision 58643 (June 1, 1994) at 8] . First, the externalities associated with DSM programs, especially environmental externalities, are very difficult to monetize. And second, some transfer payments, such as the potential for DSM to increase rates, are very important and should be considered. Ultimately, it was impossible to reach any consensus, despite literally years of debate, on how to define or implement the societal cost test. I do not believe that the "test" recommended by Ms. Keene would be any easier to implement today than it was 10 years ago.

Q. WHAT DOES THE COMPANY PROPOSE FOR EVALUATING THE COST EFFECTIVENESS OF ITS DSM PROGRAMS?

A. There is a standard test that has been widely used in the industry for evaluating DSM programs from a resource perspective known as the "total resource cost" test. This test is roughly equivalent to the societal test described above, except that it does not include externalities in the equation. Also, potential rate impacts have been widely evaluated in the industry with the "rate impact measure" test. The Company will recommend in the DSM workshops that the costs and benefits of its DSM programs be evaluated by using the total resource cost test as the primary metric, with additional consideration given to the rate impact measure. This approach would assess DSM programs from the same resource perspective currently used by Staff, without the ambiguous requirement to attempt to monetize externalities that might never reach consensus. Also, the additional consideration of potential rate impacts could be important policy considerations for DSM investments.

Q. DO YOU AGREE WITH STAFF'S PROPOSAL FOR MONITORING AND EVALUATING DSM PROGRAMS?

A. For the most part. APS would submit a monitoring and evaluation plan for each DSM program as part of the pre-approval process with Staff. APS agrees with Ms. Keene that monitoring and evaluation can provide important benefits including an accurate estimate of peak and energy savings, verification of the cost effectiveness of the program, an assessment of the effectiveness of the marketing and implementation strategies, and the receipt and acceptance of education materials by customers, builders, contractors and other key allies. APS also agrees with Staff that actual field measurements can be an important part of the monitoring and evaluation process to gauge the programs impact based on actual equipment installations and customer behavior. Field measurements could include site inspections, customer surveys, meter and billing data, and other information as appropriate for each specific program.

That said, the Company has observed that measurement and evaluation efforts and costs can be excessive and out of proportion to total DSM expenditures. Accuracy is important, but when it costs more money to measure than is spent on actually achieving reductions in demand and energy then it is not an appropriate approach or method. The monitoring and evaluation spending for some of the DSM programs in the past and some current programs in other states—especially some of the states that SWEEP provides as examples for Arizona to follow (e.g. California)—have been excessive. In addition, Ms. Keene's strong opposition to using engineering estimates in this process is misplaced (Keene at 12). Engineering estimates alone can sometimes provide an inaccurate measurement of savings because of the installation and customer behavior issues mentioned earlier. However, engineering estimates along with field inspections and customer information can provide an accurate measurement of program performance at reasonable cost. In light of the concern about the potential for excessive monitoring and evaluation requirements, the Company will recommend in the DSM workshops that the Commission set an expectation that monitoring and evaluation costs should generally not be more than 10 percent of the total DSM budget. Specific programs may incur higher or lower proportionate costs. However, the Company believes that for the entire DSM portfolio, accurate and effective monitoring and evaluation can be achieved within that guideline.

Q. WHAT DOES THE COMPANY PROPOSE FOR MONITORING AND EVALUATING THE DSM PROGRAMS IN THE EXPANDED PROGRAMS IT HAS PROPOSED?

A. The Company proposes a combination of meter and billing data, customer and trade group surveys, site inspections, and engineering estimates to monitor and evaluate our DSM programs. The particular techniques would be customized for each program depending on the nature of the program, the key identified risks and uncertainties, and the overall scope of the program. This customized monitoring and evaluation plan would be submitted to Staff as part of the pre-approval process.

V. <u>NET LOST REVENUES AND INCENTIVES</u>.

Q. PLEASE EXPLAIN THE CONCEPT OF NET LOST REVENUES AND UTILITY INCENTIVES?

A. One of the key potential benefits of DSM programs is to offset the need for a utility to supply additional resources to serve load. However, from the utility's perspective, DSM has two important differences from traditional supply resources. First, it lowers the utility's sales and revenues. Second, it can also reduce earnings because DSM costs are typically expensed and not included in the rate base where they can earn a return. Regulators have recognized that it is appropriate to keep the utility financially neutral when implementing DSM programs.

Q. HAS APS EVER RECOVERED NET LOST REVENUES IN CONNECTION WITH THE COMMISSION'S DSM PROGRAMS?

A. Yes, APS <u>both</u> recovered net lost revenues and was provided a financial incentive as part of the Commission's DSM programs from 1992 to 1999. The net lost revenue mechanism allowed APS to recover lost revenues net of reduced fuel costs. The incentive addressed lost earnings attributable to DSM. This concept was not unique to Arizona, and many other state commissions with aggressive DSM programs provided similar treatment.

Q. IF THE COMMISSION IMPLEMENTS HIGHER DSM SPENDING, WHAT SPECIFICALLY DOES THE COMPANY PROPOSE FOR NET LOST REVENUES AND FINANCIAL INCENTVES?

A. If the Commission adopts an expanded DSM program for APS in this rate case, the annual funding should include a financial adjustment to APS to reflect the net lost revenues and other lost earnings from DSM programs. This issue can be addressed in more detail in the current DSM workshops and APS will participate in discussions and proposals on this topic. The allowed recovery associated with net lost revenues and other financial considerations should be included in the DSM adjustment mechanism, which the Company has recommended in the system benefit adjustment clause, SBAC-1, as discussed in Mr. Rumolo's testimony. This annual adjustment is not an incentive for investing in DSM or achieving specific goals. The Company does not need to be incented to implement the Commission's desired DSM policy or to meet any program goals. Nor do we think that the amount should be increased based on achieved goals, such as achieving higher levels of savings. Rather, net lost revenues and incentives are a recognition of the lost revenue and earnings issues and a desire to keep DSM on a roughly level playing field compared with supply-side investments. The Company's proposed $3 million funding level for an expanded DSM program does not include any funding for net lost revenues or other related financial considerations. However, because the Company anticipates that net lost revenues will likely be addressed in the current DSM workshops we have included net lost revenues in the plan for administration as discussed in the rebuttal testimony of Mr. Rumolo.

VI. RESPONSE TO COMMISSIONER HATCH-MILLER REGARDING OTHER STATES' DSM PROGRAMS.

Q. HAVE YOU REVIEWED THE DSM PROGRAMS OF OTHER STATES IDENTIFIED IN COMMISSIONER HATCH-MILLER'S LETTER?

A. Yes. In response to Commissioner Hatch-Miller's letter, I specifically reviewed the programs of Sierra Resources (Nevada Power), Xcel (Public Service Colorado), PNM Resources (Public Service New Mexico), and Pacificorp (Utah Power & Light in Utah, Pacific Power in Wyoming). We believe that these programs are most responsive to Commissioner Hatch-Miller's request in terms of being a mix of newly expanded programs and other existing programs in several western states, which are similar to Nevada Power's program. A summary of these programs and the associated spending levels is provided in the attached Schedule TAH-1RB.

Q. PLEASE DESCRIBE EACH PROGRAM THAT YOU REVIEWED.

A. Let me begin with New Mexico. PNM Resources currently implements very limited DSM programming, essentially focused on energy efficiency education delivered on-line. The company features Internet-based self-audits for residential customers and real time energy profile information for large commercial and industrial customers. The company does not currently implement any other market transformation or traditional rebate programs of which APS is aware.

In Colorado, beginning in 2000 Public Service Colorado implemented an expanded DSM program which included new programs for both residential and commercial customers. These programs are a mix of market transformation programs and traditional rebate programs. Some of the programs include rebates for high efficiency air conditioners and an air-conditioner control demand response program. They also offer design assistance for commercial construction and the company is piloting a re-commissioning program for existing commercial buildings.

In Utah, Pacificorp has also expanded its DSM efforts through its operating company, Utah Power & Light. They offer incentives for high efficiency air conditioners and evaporative coolers, a do-it-yourself Web-based home energy audit, and a refrigerator recycling program for residential customers, as well as an air conditioning load control demand response program for both residential and small commercial customers. Programs targeted to commercial, industrial and irrigation customers include engineering assistance and incentives for improved energy efficiency and retrofit projects, lighting incentives, and a pilot program to re-commission the operations of existing commercial buildings. They are also considering new commercial and industrial interruptible tariffs, curtailable tariffs, and real-time pricing.

In Nevada, Sierra Pacific/Nevada Power offers DSM programs for residential customers which include rebates for energy star appliances, new time of use rate options, discounts on compact fluorescent lights, consumer education, energy audits, an Energy Star builder program and a pilot air conditioner curtailment program. For commercial customers they offer a pilot customized incentive program for a variety of energy efficiency improvements and a loan program through a participating bank. For both residential and commercial customers, Nevada Power commits a significant portion of overall DSM resources to customer education and market transformation initiatives such as trade shows, web content, energy consultation, energy educator speakers bureau, contractor training and the small commercial conservation university program.

Finally, in Wyoming, PacifiCorp serves approximately 70% of the state through their Pacific Power subsidiary. However, PacifiCorp has not instituted any expanded DSM programs in Wyoming. In fact, Wyoming currently has only very limited web-based education about energy efficiency, with no other market transformation or traditional DSM programs of which APS is aware.

Q. WHAT IS YOUR GENERAL ASSESSMENT OF THESE PROGRAMS AND THEIR APPLICABILITY TO APS' SITUATION?

A. The program concepts and implementation strategies from each of these programs can offer helpful ideas and strategies for APS and other utilities to consider and monitor. For example, PacifiCorp, Public Service Colorado and Nevada Power have both implemented DSM/load management programs targeted at air-conditioning use and demand response that are designed to help manage their growth, especially during peak periods. In the industry generally, several companies are experimenting with demand response programs, especially residential air conditioner control, and are implementing new time-of-use and real time price signals for customers. Another trend seen both regionally and nationally is the use of Internet-based real-time load profiles to help large commercial and industrial customers better understand and manage their energy consumption and peak demand. However, while conceptually these programs may be interesting, it is important to keep in mind that many of these programs are relatively new and have not yet demonstrated proven results.

Looking at each state, there are common local issues such as the supply of resources, the local economy, customer base, and the geography of the service territory that typically drive the level of emphasis on DSM program spending. The current resource mix and availability of generation for a utility, as well as transmission and distribution constraints, are primary drivers. For example, Nevada relied too heavily on the wholesale market for their energy needs through the recent energy crisis and is still struggling to build additional generation capacity in the state. As reflected in Assembly Bill 661 in July 2001, the Nevada legislature recognized that:

> [E]lectric utilities in this state depend on regional energy markets to purchase approximately 50 percent of the electricity needed to serve their customers in this state, and such purchases are often made pursuant to agreements with terms of 1 year or less.

I think that this situation largely prompted state officials to aggressively pursue DSM programs as well as new generation supply resources in response to a perceived problem. This viewpoint was recently reflected by Nevada Power who reported that many of Nevada Power's current DSM programs were originally piloted in 2001 in response to power supply shortages (Direct Testimony of Robert Balzar, 2003 Nevada Power Company Cost Recovery Filing, at 2).

Because the supply situation in Arizona is significantly different than in Nevada, the overall DSM spending level of roughly $11 million per year in that state is not presently warranted for APS. However, Nevada Power is similarly situated to APS when considering issues such as robust growth in our service territories, healthy residential construction activity, and a high summer peak. So, some of their program ideas may work in Arizona and we can certainly learn from each other. For example, APS was somewhat surprised that Nevada Power had not implemented a more aggressive effort for improving the energy efficiency of residential new homes. In conversations we have had with Nevada Power and the Nevada State Energy Office, they have expressed interest in developing a residential builder program more like APS' and they want to understand APS' experiences in implementing such a program. In fact, an official from the Nevada energy office recently attended an APS-sponsored building science training class in Phoenix to learn about our experience in transforming the residential new construction market.

In contrast to Nevada, Colorado and Utah have winter peaks or dual peaks so some of their programs do not easily translate to Arizona. However, we have noted that even these utilities offer air-conditioner based programs. As a result of this analysis, we believe that residential air conditioner control could be a beneficial program for Arizona and the recent experiences of these utilities in implementing residential air conditioner control should be closely monitored.

Q. DO YOU BELIEVE THAT APS SHOULD CONTINUE TO MONITOR THESE DSM PROGRAMS FROM OTHER WESTERN STATES?

A. Yes. It is valuable to examine and monitor programs and initiatives that are being undertaken in other states in the West. This can help identify trends and point to areas of innovation, as well as indicate programs that have not been successful or cost-effective. In the West, utility DSM program trends include the continued use of technology and Internet communication channels to deliver information and provide utility program control and feedback. Examples are the widespread use of the Internet to support real time load profile information for large commercial and industrial customers, and use of interactive load control technology to trim residential peak cooling loads. In addition, all of the utilities that were studied include on-line consumer education about energy efficiency on their websites, including on-line energy audit functions for residential and commercial customers.

Q. DO THE PROGRAMS IN OTHER WESTERN STATES SUGGEST TO YOU THAT APS NEEDS TO CHANGE ITS APPROACH TO DSM TO IMPLEMENT THESE OTHER PROGRAMS?

A. No, on the contrary, APS' analysis of DSM programs in other states in the West reinforces that the Company is consistent with industry trends with its current and planned DSM efforts, and I have discussed in this rebuttal testimony how APS believes that expanding its DSM programs would be beneficial. This analysis also confirms that our current programs and accomplishments compare favorably with neighboring states. Like other regional utilities, APS includes extensive on-line educational materials. Similarly, APS focuses considerable attention on improving cooling efficiency. Like other states in the Southwest, improving cooling efficiency typically represents the biggest opportunity for customer energy savings while simultaneously offering the greatest potential for reducing utility peak demand. In Arizona, APS offers residential new construction and existing residential home programs as well as pilot commercial programs designed to improve cooling efficiency and reduce summer peak demand.

Not surprisingly, however, some significant program differences are apparent when comparing APS to other regional utilities. Due to Arizona's rapid population growth, one of the best savings opportunities in APS' service territory is improving the efficiency of new residential construction. As such, APS has focused considerable attention on this market segment—more so than most regional utilities. As evidence of this focus, Arizona currently has regional and national recognition as a leader in energy efficient construction, with more Energy Star homes and guaranteed heating/cooling homes built or committed than in any other state, and Arizona is clearly ahead of the region.

So, although it is good to be aware of efforts in other states, it is also important to consider the unique factors in each state that have resulted in specific funding levels and areas of program focus. APS has taken a close look at the programs that we believe would be most suitable for APS and have included some of these ideas in the Company's proposal for the expanded DSM program discussed in my rebuttal testimony.

VII. CONCLUSION.

Q. CAN YOU STATE YOUR CONCLUSIONS REGARDING THE VARIOUS DSM PROPOSALS IN THIS CASE?

A. Yes. APS agrees with Staff that expanded DSM programs are warranted and could be cost-effective for our customers. Accordingly, APS proposes to expand its current successful residential DSM programs, as well as institute new DSM programs for residential, commercial, industrial and institutional customers. The Company's proposal would continue to focus on programs that can help manage growth, especially during peak periods. APS also proposes to continue to follow the market transformation approach because it yields the most benefits at the lowest cost to our customers. These new programs can be implemented by APS for approximately \$3 million per year, which achieve approximately 50% of the demand savings and nearly 25% of the energy goals proposed by SWEEP, with only roughly 10 % of the recommended spending levels of either RUCO or SWEEP.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

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Appendix A
Statement of Qualifications
Thomas A. Hines

Thomas A. Hines is an energy efficiency consultant, retained by APS as the program manager of demand side management/market transformation programs. In this role Mr. Hines plans, develops, and implements APS' energy efficiency and peak load management programs including the Performance Built Home program, APS Qualified Contractor program, the Power Partners voluntary load management pilot program, and the Commercial Facility Manager Training pilot program.

Mr. Hines graduated from Rutgers University in 1990 with a Bachelor of Arts degree in psychology. In 1994, he earned a Master's Degree in Environmental Planning from Arizona State University College of Architecture and Environmental Design. During this time, Mr. Hines worked for both Rutgers University and Arizona State University as a research and teaching assistant.

Prior to graduation from Arizona State University, Mr. Hines served as a technical specialist with EcoGroup, Inc. a utility industry environmental consulting and software design firm based in Tempe, Arizona and then went on to become Manager of Environmental Programs. At EcoGroup Mr. Hines worked with over 30 electric, gas and water utilities nationwide. He was a key member of the team which developed and enhanced the multi-award winning *In Concert with the Environment* high school education curriculum. He was also a key developer of the *Good Cents Environmental Home* program, and the *Business Edge* energy analysis tool. In addition, Mr. Hines worked extensively with water utilities throughout the western region, and created the *Water Cents* home water audit program, which was adopted by utilities in California and Washington. As a program manager, he had the overall responsibility for the successful implementation of energy and water efficiency programs for customers such as Southern California Water Company, Sacramento Municipal Utility District, Metropolitan Water District, Los Angeles Department of Water and Power, Gulf Power, Alabama Power, Georgia Power, Puget Power, City of Redmond Washington and Woodinville Water District in Woodinville, Washington.

In 1997, Mr. Hines contracted with the consulting firm Hagler-Bailly as program manager of APS' market transformation program, holding primary responsibility for designing, developing and implementing APS' DSM/market transformation programs. While at APS, Mr. Hines has collaborated on extensive consumer education materials including the Homebuyer's Guide to New Construction, the Consumer's Guide to an Energy Efficient Air Conditioning System, a series of 14 Energy Answers fact sheets, and numerous brochures, newsletters, article placements, bill inserts, and other energy efficiency information.

Mr. Hines has contributed information and articles to publications by Arizona State University, the Energy and Environmental Building Association, the American Water Works Association, American Builder, Apartment News, and Arizona Vision Weavers magazine. Mr. Hines has also participated in the Irrigation Association, the American Water Works Association, the Energy and Environmental Building Association, the California RESPAC Water Conservation Committee, and the Arizona Energy Code Committee.

MATRIX OF WESTERN REGION DSM PROGRAMS

Segment	DSM Program Type	APS	Nevada	Colorado	Utah	New Mexico	Wyoming
RES	Home energy audit (online)	X	X	X	X	X	X
	Efficient AC rebates			X	X		
	Direct AC load control			X	X		
	Refrigerator Recycling				X		
	CFL direct sales (no rebates)			X			
	CFL rebates		X		X		
	Clothes washer rebate		X				
	TOU Rate	X	X				
	Qualified Contractor	X					
	Guaranteed heating/cooling	X					
	Building Science Training	X					
COMM/IND	Meter data/load profile			X	X	X	
	Custom efficiency incentives		X	X	X		
	Peak load response (paid)				X		X
	Business Energy Audit	X				X	
	Efficient AC Rebates			X			
	Energy design assistance			X			X
	Building Operator	X					
	Peak load response (voluntary)	X					
	Direct load control			X			

State of Utah - DSM Programs (PacifiCorp)

Customer Segment	Program Name	Program Focus	Description	Comments	Funding
RESIDENTIAL	Cool Cash	Evaporative Cooling	$300 rebate for first time install, $100 rebate for replacing existing evap cooler with qualifying new unit	Potential for lots of free riders: Can greatly increase infiltration rates	Estimate PacifiCorp spent $20 million + for all Utah DSM programs in 2002 (source = AESP Teleconference 3/19/03)
RESIDENTIAL	Cool Cash	High Efficiency AC	$250 rebate for 12-12.9 SEER, $350 rebate for 13 SEER or higher	In Arizona, 90%+ of all new AC's are 12 SEER or higher, Program does not deal with install issues, significant admin required	
RESIDENTIAL	Cool Keeper	Direct AC Load Control	June-Aug in targeted area, peak weekdays max 100 hrs/yr	Customers receive $20 "thank you" credit on October bill	
RESIDENTIAL		Refrigerator Recycling	Customers receive $40 incentive plus 1 CFL per fridge.	Up to 2 per household, must be in working condition.	
RESIDENTIAL	Home Comfort Profile	"Do it yourself" home audit	Customer completes a paper audit survey and returns it to utility to receive energy saving tips.		
RESIDENTIAL	CFL Program			Referenced in AESP Presentation on 3/19/03, No listing of program on website.	
COMMERCIAL	Energy Profiler	Meter data	Meter info posted daily to website.	Cost = $260 set up fee, $32 monthly fee.	
COMMERCIAL (new construction)	Energy FinAnswer	Custom energy efficiency incentive program	Provides free engineering study to evaluate options and incentives = $0.12 per kWh of projected annual savings + $50 per average monthly on-peak kW savings.	Available for new construction projects in the design stage. Savings based on improvements over baseline construction.	
COMMERCIAL (existing retrofit)	Retrofit Incentive	Custom energy efficiency incentive program	Provides incentives for upgrades to existing lighting, heating/cooling, motors, vending machines.	Same basic format as the new construction Energy FinAnswer program.	
COMMERCIAL	Energy Exchange	Peak load curtailment	"Demand response" voluntary paid curtailment.	Eligible for customers with > 1MW load	

State of Wyoming - DSM Programs (PacifiCorp)

Customer Segment	Program Name	Program Focus	Description	Comments	Funding
RESIDENTIAL	Home Comfort Profile	Self home audit	Customer completes a paper audit survey and returns it to utility to receive energy saving tips.	Same as Utah audit program	According to SWEEP, less than $1mill/yr for all Wyoming programs.
COMMERCIAL	Energy FinAnswer	New commercial construction and retrofit	Free engineering, technical assistance and financing.	No rebates or incentives.	
COMMERCIAL	Energy Exchange	Peak load curtailment	"Demand response" voluntary paid curtailment.	Eligible for customers with > 1MW load	Same as Utah program.

State of New Mexico - DSM Programs (Public Service New Mexico)

Customer Segment	Program Name	Program Focus	Description	Comments	Funding
RESIDENTIAL	Home Energy Analysis	Self home energy audit	Customer completes audit on-line, print, or CD to receive energy saving tips.	Nexus EnergyGuide. Also includes Energy University	SWEEP estimates $2 million per year for all DSM programs in New Mexico.
COMMERCIAL	Business Energy Analysis	Self business audit	Available on-line only.	Nexus EnergyGuide.	
COMMERCIAL	PNM Profiler	Hourly energy use profiles	Available for large C&I customers. Provides hourly energy use profiles on-line.	For-fee service.	

State of Colorado - DSM Programs (Excel Energy)

Customer Segment	Program Name	Program Focus	Description	Comments	Funding	Energy Saving Targets
RESIDENTIAL	Summer Savings AC Rebates	High efficiency cooling replacements	Requires 13+ SEER. Rebate = $350 plus $25 for proper sizing.	Special promotion for fall 2003 = extra $100 rebate.	According to SWEEP - 2002 = $10 mill, 2003 = $11.2 mill, 2004 = $17 mill (All programs)	According to SWEEP - 2002 = 27 GWh/yr 2003 = 34 GWh/yr 2004 = 62 GWh/yr (All programs)
RESIDENTIAL	Saver's Switch	AC direct load control	Control of AC compressor during peak summer days.	Customers receive $25 incentive/summer		
RESIDENTIAL	Home Analyzer	On-line self home energy audit program	Includes energy analyzer, quick energy analyzer, appliance energy calculators.	Nexus EnergyGuide products.		
RESIDENTIAL		Home lighting	Direct sales of compact fluorescent bulbs.	No rebates or incentives.		
COMMERCIAL	Saver's Switch	AC direct load control	Control of AC compressor during peak summer days.	Customers receive $5/ton/month. Lists 15,000 businesses participating.		
COMMERCIAL	Recommissioning	Energy efficiency for existing commercial buildings	On-site analysis to identify opportunities. Customize incentives to reduce costs to a 1-year payback.		SWEEP estimates $1 million in 2003.	
COMMERCIAL	Summer Savings AC Rebates	Small commercial HVAC replacement	Requires 13+ SEER. Rebate = $350 plus $25 for proper sizing. For larger systems between 65,000 - 249,000 btu/hr = $60/ton.	Additional $25 for proper sizing.		
COMMERCIAL	Custom Efficiency	C&I energy efficiency bidding program	Issues 7 RFP's for projects. Incentives = $530/kW for efficiency or fuel switching, $330 kW for load shifting. Max per RFP = $1 million.	Considered primary commercial program.	According to SWEEP = $4 million in 2003, $6 million in 2004	Goal = 18.5 MW by summer 2005.
COMMERCIAL	Energy Design Assistance	C&I technical assistance	Free consultation and computer modeling energy simulations.	Provides incentives for improvements of $1-$2 per peak kWh saved.	$1 million in 2003, $2.5 million in 2004.	
COMMERCIAL		C&I efficiency financing	$0 down financing with competitive fixed rates and payments on monthly bill.	Must be used for products and services purchased from Excel Energy Retail.		
COMMERCIAL	Demand Display, Profiler, Expert	C&I load tracking and analysis	Demand display monitors and displays real time energy use, profiler provides analysis software, expert offers fully automated demand management	For-pay service.		

State of Nevada - DSM Programs (Sierra Pacific/Nevada Power)

Customer Segment	Program Name	Program Focus	Description	Comments	Funding
RESIDENTIAL		Compact fluorescent light bulb (CLF) discounts	Works with retailers to provide discounted prices on compact fluorescent bulbs.	CFL bulbs as low as $.99 for 14-23 watt twist style bulbs. Offered through Home Depot/Lowe's.	According to AESP presentation on 3/19/03 funding 2002 = $3 M 2003 = $11.2 M (All programs)
RESIDENTIAL		Appliance rebates	Provides $50 rebates for E Star qualified clothes washers.		
RESIDENTIAL	Home Energy Advisor	On-line energy self audit.	Uses a home analyzer program developed by Lawrence Berkeley Labs.		
RESIDENTIAL	TOU rate		New rate offered to encourage load shifting.		
RESIDENTIAL	Low Income Assistance		Standard low income assistance program.		
COMMERCIAL	Sure Bet Program	Prescriptive and customized rebates.	Prescriptive rebates for a huge list of lighting, HVAC, motors, etc.	Custom rebates based on modeled energy savings = $100/peak kW, $0.03/annual kWh savings	

Nevada Power indicates a number of additional programs in their AESP presentation of 3/19/03, however, there is no listing of any of these programs on their web site:

3100 "field investigation" customer audits
3459 AC load management controllers installed
New construction builder support/energy star
Small commercial customer education
Irrigation customer education
Low-income weatherization = $1.3 million
"Market and technology trials" = $200,000
Refrigerator collection
Residential photovoltaic
AC Tune-up/duct sealing/replacement

EXHIBIT
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REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

VICE-PRESIDENT
CHARLES RIVER ASSOCIATES INC.

March 30, 2004

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REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-03-0437)

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My Name is William H. Hieronymus. My address is Charles River Associates Incorporated, John Hancock Tower T-33, 200 Clarendon Street, Boston, MA 02116-5092. I am a Vice President of the company and an economist by training, specializing in energy and in particular the electricity sector.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN THIS PROCEEDING AND, IF SO, IS YOU BACKGROUND DESCRIBED IN THAT TESTIMONY?

A. Yes. I filed testimony as part of Arizona Public Service Company's ("APS") direct case. My resume is appended to that testimony.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. All of my testimony concerns the appropriateness of transferring the PWEC Arizona assets to APS and including them in ratebase at their depreciated cost. With regard to this subject, I am responding to Staff and intervenor testimony in a number of areas. First, I discuss why, despite Staff and intervenor testimony to the contrary, it is important to consider the rate-basing of the PWEC Arizona assets in the same manner that would be done if the assets had been built by APS in the first instance. In that context, I reprise my Direct Testimony as to why

PWEC felt it necessary to build these assets, focusing mainly on the issue of whether they were built primarily to serve APS' load.

The next section of my testimony responds to other elements of ACPA witness Dr. Joseph Kalt's testimony, primarily his testimony that PWEC's offer to sell the assets to APS somehow "proves" that the assets are uneconomic to APS, his characterization of the purchase as little more than an expensive insurance premium, his argument that APS would be over-reliant on owned generation if the transaction is approved, and his assertion that the transaction will adversely affect the competitive wholesale market.

While my position continues to be that the Commission should apply the traditional standard for including utility-owned generation in rate base, the next section of my testimony addresses the current value of the PWEC Arizona assets. I first explain the methodologies generally used to value assets. These include replacement cost, comparable sales, and discounted cash flow. I then discuss Staff witness Mr. Salgo's and RUCO witness Mr. Schlissel's discounted cash flow analysis. Finally, I respond to Questions 4 and 5 of Commissioner Gleason's letter to rate case participants.

II. SUMMARY OF TESTIMONY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY AND CONCLUSIONS.

A. I first reiterate a conclusion from my Direct Testimony that the proper standard to be used in determining whether the PWEC Arizona assets should be included in APS' ratebase is the prudence standard and, moreover, that prudence should be assessed as of the time that the assets were planned and constructed. That prudence is the appropriate standard is not disputed, at least not explicitly, by any opposing witness. What is controversial is the timeframe – 1999-2001 or today – relevant for assessing prudence. My conclusion that the earlier timeframe is appropriate rests on three pillars. First, as discussed at length in my Direct Testimony, as well as in the testimony of other witnesses, as a result of the Electric Competition Rules and the 1999 Settlement Agreement, Pinnacle West had no choice but to have PWEC build these assets to support the economy and reliability of serving APS' load. This conclusion is buttressed by a record that establishes that these assets were built primarily to serve APS' load, a subject that I discuss separately.

Second, with the Commission in its Track A order having largely undone the relevant parts of the Electric Competition Rules and relevant parts of the 1999 Settlement Agreement, it has essentially reverted to the status quo ante in which APS is a vertically integrated utility with traditional needs to control enough generation to meet its native load. Hence, treating the PWEC Arizona assets as if the relevant parts of the Electric Competition Rules and 1999 Settlement Agreement had never existed is appropriate. Third, reunifying the PWEC and APS assets as was intended in the Electric Competition Rules and 1999 Settlement Agreement is an equitable solution to the harm that bifurcation otherwise causes Pinnacle West and its subsidiaries. In short, prudence should be assessed in terms of whether APS reasonably could have concluded that building the PWEC assets was in its ratepayers' best interest under a regulatory regime that did not require or even encourage the separation of generation from other utility functions.

My second topic is the APS-centric nature of PWEC's resource plans and decisions. The case that the PWEC assets were built primarily to serve APS' load is established in my Direct Testimony and the direct and rebuttal testimony of other witnesses for the Company. My rebuttal focuses on contrary assertions by intervenors. For the most part, they rely on APS documents that purport to establish that the PWEC units were merchant units, planned to serve the market generally. It is undisputed that PWEC was a "merchant" generator that had no native load of its own. This was required by Commission policy. Nor is it disputed that the assets were sited and sized with the expectation that off-peak energy would be sold at wholesale. However, nothing in these documents or Staff and intervenor witnesses assessment of them undercuts the basic facts that the type, timing and location of the PWEC assets was responsive to APS' requirements, nor that at critical times when output could have been sold to California under lucrative long term contracts, Pinnacle West reserved them to meet APS' native load.

The fourth section of my testimony discusses various issues raised by ACPA witness Dr. Kalt. Dr. Kalt asserts that purchasing the PWEC Arizona assets is a bad deal for APS' ratepayers. However he performs no analysis to support this assertion. Indeed, his sole basis appears to be the assertion that if Pinnacle West is willing to sell the assets to APS at book value this necessarily "proves" that they are worth less than book value. While Company management witnesses appropriately testify concerning the motivation for the transaction, I demonstrate that the tautological link between the willingness to offer and lack of value that Dr. Kalt seeks to establish is simply incorrect.

Dr. Kalt also testifies that buying the PWEC assets is an uneconomic insurance policy against high further prices. I show that he is confusing insurance with purchasing a producing asset. Paying for the PWEC assets is like buying a house, not like insuring it against fire and flood, although there is an insurance or hedge value inherent in acquiring a power plant.

Dr. Kalt also provides a comparison that seeks to establish that APS would be over-hedged, relative to other WECC utilities, if it buys the PWEC assets. His analysis is factually flawed, as discussed in Mr. Bhatti's Rebuttal Testimony. The point that I make is that nothing in his comparison establishes what level of vertical integration is in APS' ratepayers' interest. Indeed, the least covered utilities are those that were most damaged by the power crisis of 2000-2001.

Finally, Dr. Kalt asserts that buying the PWEC assets is an exercise of vertical market power by APS. However, to the extent that such an allegation has even superficial validity, it rests entirely on his undemonstrated assertion that buying the PWEC assets at book value is a purchase (and cost pass-through) of uneconomic assets.

Section V of my testimony discusses Staff and intervenor witnesses' assertions that the value of the PWEC assets is less than the price that APS will pay if the transfer is approved. I explain the different types of analyses typically used in asset valuation: replacement or reconstruction cost, comparable sales and net present value of cash flows ("DCF"). Mr. Wheeler and Mr. Bhatti testify on reconstruction or replacement cost and DCF. I provide an analysis of available "benchmark" transactions that can be used to establish comparable value. I conclude that the price of the PWEC assets is below the market comparables, even when the Track B contract is taken into account.

As noted above, replacement cost is a consideration in determining market value. Replacement cost establishes the net present value of revenue requirements for the PWEC assets (assuming APS ownership of the PWEC assets) versus the equivalent revenue requirements assuming that load is met without buying the PWEC assets. APS witness Mr. Bhatti provides an analysis that demonstrates that the NPV of revenue requirements is lower than a variety of feasible and not-so-feasible alternatives.

Staff witness Mr. Salgo and RUCO witness Mr. Schlissel also provide DCF and NPV analysis. Mr. Salgo relies on an assumed resource plan in which the Track B contract is retained and APS builds 1,700 MW of new capacity, similar to the PWEC assets, in 2007. He finds that the PWEC assets are essentially breakeven relative to his alternative. Mr. Schlissel compares the cost of power from the PWEC assets to the cost of purchasing from the market. He finds that the PWEC assets have a positive NPV, relative to the alternative, even though he truncates the analysis for unexplained reasons well before the end of the 30 year book life of the assets. I conclude that his analysis on its face supports the economic value of APS purchasing the assets and that had he properly carried the analysis through the life of the assets, he would have found them far more cost effective – by more than $400 million more present value dollars.

These witnesses, as well as ACPA witnesses, emphasize that in the early years of the analysis, rate-basing the PWEC assets is more expensive than the Track B contract and buying power from the market. This is not surprising, important or even relevant. Prudence analysis of purchases appropriately looks at value over the relevant life of the contract or asset. Indeed, the whole purpose of using NPV is to permit tradeoffs between near term costs and longer term savings. The higher near term cost of rate-basing tells nothing about the ultimate value of the PWEC assets. It is due entirely to regulatory accounting. I demonstrate that the delayed "cross-over" between revenue requirements of assets and market purchases (including the Track B contract) is characteristic of <u>all</u> utility assets and, indeed, that market prices generally will not support the full accounting cost of new assets, including assets outside of the electricity industry.

Finally, the last section of my testimony responds to Questions 4 and 5 posed by Commissioner Gleason, in his letter to APS dated September 5, 2003. I conclude that other state commissions have generally supported the purchase of merchant plants including assets purchased from affiliates, though there have been few such transactions. I also conclude in response to Question 5 that the proposed asset transfer will not harm the competitive wholesale market.

Q. IF YOU HAD TO DISTILL A CENTRAL MESSAGE FROM YOUR TESTIMONY, WHAT WOULD IT BE?

A. The relevant standard for evaluating the purchase of the PWEC Arizona assets by APS is the prudence standard. The only competing standard is the "used and useful" standard and no witness claims that the PWEC assets will not be used and useful to APS. I continue to believe that prudence should be assessed on the same basis as would have been used if APS had built the assets itself, as it would have absent the Electric Competition Rules and 1999 Settlement Agreement.

If the Commission concludes otherwise, then the relevant question is whether acquisition of the PWEC Arizona assets at book value is prudent for APS today. Mr. Bhatti's analysis shows that, over a wide variety of alternatives, the NPV of revenue requirements will be lower if the PWEC assets are purchased and rate-based. Mr. Salgo's analysis, taken on its face, suggests that revenue requirements are no higher if the assets are purchased than if they are not. Mr. Schlissel's analysis, again taken on its face, shows that revenue requirements will be less if the assets are purchased. As discussed in Mr. Bhatti's testimony and in mine, both Mr. Salgo's and Mr. Schlissel's analyses are seriously flawed and significantly understate the value to APS customers from rate base treatment of the PWEC assets.

The Commission's regulations properly establish a presumption that APS' actions are prudent and require "clear and convincing evidence" before concluding that an investment that it makes is imprudent. Even if the Staff and intervenor evidence is taken at face value, it fails by a very wide margin to demonstrate that APS' purchase of the PWEC Arizona assets is imprudent and not in the interests of its ratepayers.

III. <u>WHY PRUDENCE IS THE RELEVANT TEST</u>

Q. DO STAFF AND INTERVENOR WITNESSES DISPUTE THAT THE PRUDENCE OF THE DECISIONS TO BUILD THE PWEC ARIZONA ASSETS, AND THE PRUDENCE OF THEIR CONSTRUCTION MANAGEMENT ARE RELEVANT TO THIS PROCEEDING?

A. Yes, they do. Their fundamental position is that, since PWEC is a separate company that was created to be a GENCO (not subject to ACC regulation), the prudence of these original planning decisions is irrelevant as is the prudence of the management of construction of the PWEC assets. In their view, all that should matter is the transfer price and APS' need for the assets. That is, the prudence of adding the PWEC assets to APS' generation portfolio today should be assessed solely from a current perspective (Jaress testimony page 8 and 9).

Q. DO YOU AGREE THAT THE PRUDENCE OF THESE PLANNING DECISIONS AND PROJECT EXECUTION IS IRRELEVANT?

A. No, not under the circumstances extant in this case

Q. WHAT DISTINGUISHES THIS CASE FROM A MORE TYPICAL CIRCUMSTANCE?

A. The principal distinguishing fact is that the Commission has reversed critical elements of the Electric Competition Rules and the 1999 Settlement Agreement. Effectively, the Commission has reregulated the APS generating assets that were scheduled to be transferred to PWEC no later than January 1, 2003. And, for reasons largely unrelated to Commission action, retail access in Arizona has not occurred in meaningful amounts. Moreover, even if it might in the future, APS has "provider of last resort" obligations for all its customers in the form of Standard Offer service. Thus, APS remains responsible for supplying essentially its entire historic load base reliably at cost of service regulated rates. Hence, APS and the Commission find themselves today in essentially the same position as would have occurred had Arizona never embarked on electricity restructuring, with one very significant exception.

That exception is that the new power plants that APS otherwise would have built to meet its growing needs are severed from the older generating assets and housed in PWEC. Effectively, rate-basing the PWEC Arizona assets merely restores the *status quo ante* that would have existed if the Commission had not embarked on the essentially reversed course of restructuring that assumed full reliance by load serving entities on a competitive, merchant generation market.

There also is another equitable reason for treating the assets as if they always had belonged to APS. At the time the construction of these assets was planned and initiated, Pinnacle West reasonably relied on a belief that the course of action laid out in the Electric Competition Rules and 1999 Settlement Agreement would in fact occur. Under that course of action, PWEC would have had a large and diverse portfolio of assets, blending old depreciated assets with new and undepreciated assets, baseload, cycling and peaking generation, and generation with a well balanced diversity of fuel types. This has been undone by the Commission's Track A decision to keep the existing generation in APS. My point is not that the Commission's decision to retain the existing generation in APS was right or wrong. Rather, it is that the decision had important consequences that should be addressed in this proceeding and rectified by the Commission.

Among other consequences, this unbundling puts a severe financial strain on PWEC from which consequences APS is unlikely to be fully immune. As I shall describe later in my testimony in a different context, even cost-effective assets are likely to incur losses in the early years of their existence if their output is sold at market prices. In a larger and more diverse portfolio, such as was to exist under the terms of the 1999 Settlement Agreement, this is counterbalanced by significant profits on depreciated assets. The Track A Order's deconstruction of the unified APS/PWEC portfolio severed the depreciated assets that, other things being equal, would be the most profitable in the near term if their output were sold at market rates from the new and largely undepreciated assets.

Q. DOES IT MATTER WHETHER THE PWEC ASSETS WERE PLANNED BY PWEC FOR APS LOAD?

A. Yes, although rate-basing is appropriate even if they had not been so intended. The key issue is whether the PWEC Arizona assets would have been prudently planned and built by APS in meeting its load absent the restrictions imposed by the 1999 Settlement Agreement and the Electric Competition Rules. In this context, it is germane that the assets were planned to meet APS' load. This relevance is for two reasons. First, the fact that Pinnacle West built assets in the belief that APS could not itself build and that the market could not be relied upon to supply APS' needs in an economic and timely basis buttresses the equitable case for rate-basing the assets. Second, the fact that the contemporaneous planning studies so focused on APS' needs creates a record that can and should be reviewed in order to determine whether these assets would have been prudently built by APS had it retained the ability to do so.

IV. <u>WHETHER THE PWEC ARIZONA ASSETS WERE BUILT TO SERVE APS CUSTOMERS</u>

Q. DO STAFF AND INTERVENOR WITNESSES DISPUTE THE CLAIM THAT THE PWEC ARIZONA ASSETS WERE BUILT TO SERVE APS LOAD?

A. Yes. Ms. Jaress, Mr. Schlissel and Dr. Kalt all assert that these assets were not built to serve APS load. Mr. Higgins and Mr. Salgo take the same position but do not attempt to provide evidence to support it.

Q. PLEASE BEGIN WITH MS. JARESS'S TESTIMONY. WHAT IS HER BASIS FOR CONCLUDING THAT THE ASSETS WEREN'T BUILT TO SERVE APS LOAD?

A. She relies on various public statements made by APS or PWEC to the effect that the PWEC assets would be merchant assets and that PWEC would seek to serve loads throughout the region.

Q. DOES THE EVIDENCE SHE PRESENTS SUPPORT THE CONCLUSION THAT THE PWEC ARIZONA ASSETS WERE NOT BUILT TO SERVE APS' LOAD?

A. No. She relies first on a statement by Ed Fox at the Redhawk siting hearing that Redhawk would be merchant plants, competing in the competitive market. This is merely a factually accurate statement, consistent with the Electric Competition Rules, that it was anticipated that APS customers would be served from the competitive market. It says nothing about whether these particular assets were expected to serve the APS load.

She next relies on an undated document ascribed to Bill Stewart, the PWCC executive in charge of the GENCO and later of PWEC, that identifies Redhawk as a merchant station, which under the Electric Competition Rules it had to be. She then quotes a passage indicating that PWEC intended to capture part of the regional growth potential, and opines that the statement "can be easily interpreted to mean that PWEC...did not envision the construction and purchase of plants was just to serve APS." What Ms. Jaress ignores is that PWEC was not just building the PWEC Arizona assets. It bid successfully (initially) on assets in Nevada and on SCE's share of Palo Verde and Four Corners. It bid unsuccessfully on a PG&E station in California and on other assets in Nevada. It was indeed correct that PWEC had ambitions beyond serving APS' customers. However, this is not relevant to the question of whether the PWEC Arizona assets were built in order to assure that APS loads could be served reliably.

Her next reliance document is the press release announcing the joint venture with Calpine. The language she cites, quoting Bill Post, is that "we are committed to meeting the growing needs of our customers as well as pursuing new generation opportunities in competitive markets." This focus on "the growing needs of our customers" hardly supports the conclusion that the assets were not built to serve APS' load. Indeed, it is evidence of precisely the opposite.

The reference to the Calpine joint venture is a useful place to reiterate something that I said in my Direct Testimony. The key thing about the PWEC Arizona assets was not whether they would be owned 100 percent by an APS affiliate (the Calpine joint venture would have caused Calpine to own part of West Phoenix) but whether sufficient assets would be built or bought by PWEC on a timely basis to assure that APS' loads would be served economically and reliably. By building these particular assets, even if they had been jointly owned, PWEC assured that the plant necessary to meet APS' reliability and energy needs would exist.

Q. WHAT OTHER DOCUMENTS DOES MS. JARESS RELY ON?

A. The next document is the 1998 SEC Form 10-K. She relies on a statement that one part of <u>APS'</u> strategy was to expand its generation asset base to support growth the competitive power marketing arena. This rather bland statement from 1998 hardly supports the view that the PWEC Arizona assets were not intended to support APS. Indeed, these assets had not yet been announced, let alone built, and PWEC did not exist. I note also that a later statement in the same paragraph states that "Underpinning APS' competitive strategies are the strong growth characteristics of APS' service territory." This indicates that APS load was the driving force behind all APS, and later PWEC, expansion plans. It also supports the rather obvious conclusion that, but for the 1999 Settlement Agreement and the Electric Competition Rules, the PWEC Arizona assets would have been built by APS.

The last reliance quotation is from a presentation by Bill Post to analysts in October 2000. This is a quite curious quotation for her to rely on. The key sentence that she quotes reads, "We have sized our generation expansion plan, when you combine that with our existing generation, to what we think the native load will be, gives us the ability to deal with changes in regulation, the re-regulation of this market." The statement that the total generation plan, including PWEC, was sized to cover APS' native load hardly supports the conclusion that the PWEC Arizona assets were not planned and built to serve APS' needs. Again, it supports the opposite conclusion.

Q. PLEASE TURN NOW TO THE TESTIMONY OF MR. SCHLISSEL AT PAGES 19-24. HE QUESTIONS WHETHER THE PWEC UNITS WERE BUILT PRIMARILY TO SERVE APS NEEDS. DOES HE EVER COME TO THE CONCLUSION THAT THEY WERE NOT?

A. No. Interestingly, Mr. Schlissel never concludes, one way or another, on this issue. The closest that he comes to reaching a conclusion is to suggest (in question form on page 19) that there is evidence that suggests they were not built primarily to serve APS loads.

He first cites briefly to various 1998 and 1999 studies to support the proposition that PWEC (as it later became) intended to serve competitive markets throughout the region. However, this says nothing about these particular assets.

Two of the citations are worth some response. His fourth bullet point notes that a 1999 risk assessment indicated that PWEC was planning to control more capacity than was needed to meet APS' requirements. First, this is not inconsistent with the idea that these particular Arizona plants were built to serve APS. Second, as I discussed in my Direct Testimony, at that time, PWEC was pursuing a variety of sources of power, not all of which could be expected to come to fruition, as indeed they did not. His second citation is to the press release announcing the Redhawk units, which stated that these units would compete in the deregulated energy markets of Arizona, California and other Western states. As I shall discuss later, even the most APS-centric units would need to compete in the broader region. He also cites to the same press release for the proposition that the Palo Verde site was chosen to give access not only to Arizona but also to California. Again, this would have been appropriate for APS-centric units and, indeed, for APS-built units.

Q. DOES MR. SCHLISSEL CONCEDE THAT THERE WAS A RELATIONSHIP BETWEEN PWEC'S CAPACITY PLAN AND APS' REQUIREMENTS?

A. Yes. At page 20, he states that by late 2000 Pinnacle West's capacity plans tied the addition of new generation to APS' peak load. I discussed this at some length in my Direct Testimony. However, he also argues that "the Company clearly was not abandoning or sacrificing its interest in selling power to California, Nevada or other areas in the Desert Southwest during the non-peak months."

He then provides a series of quotations to show that PWEC would have the ability to produce energy not needed by APS that could be sold to the larger market. Indeed, the first citation expressly <u>limits</u> such sales to generation <u>not</u>

needed by APS. The remaining citations indicate that other than in the third calendar quarter, when APS' needs are the greatest, PWEC would have surplus energy to sell to the market.

Q. DOES THE FACT THAT PWEC WOULD HAVE ENERGY SURPLUS TO APS' NEEDS IN OFF-PEAK MONTHS SUGGEST THAT THE PWEC ARIZONA UNITS WERE NOT PLANNED TO MEET APS' REQUIREMENTS?

A. No. For decades, APS has exported off-peak power and profited by doing so. The same has been true for most, if not all Southwestern utilities. Indeed, it would be foolish to determine how much to build and what kind of plant to build while ignoring the fact that certain regions of the WECC, particularly California and Nevada, are chronically short of both energy and capacity. It is neither new nor surprising that building capacity that could economically provide exportable energy that was not needed for native load customers would be consistent with meeting APS' needs in the most economic way.

The PWEC/APS planning studies at relevant times indicated that building combined cycle units was more economic than building peakers. It must be remembered that at the time, California was very short of capacity and imported energy from elsewhere (as it still does). During the roughly 75 percent of the time when gas-fired capacity was "on the margin" (that is providing the non-baseload generation needed to meet loads in all but low load and hydro run-off periods) in California, and thus set the price, the heat rate of the marginal unit was at least 10,000 BTU/kWh and often higher still. The PWEC combined cycle units had a heat rate of about 7,000. Hence, there was a profit to be made of about 50 percent over variable cost, even if the California price was set at the marginal cost of generation.

Q. AT PAGE 21, MR. SCHLISSEL CONTESTS MR. BHATTI'S CLAIM THAT THE LOCATION OF THE PWEC UNITS DEMONSTRATES THAT THEY WERE BUILT TO SERVE APS' CUSTOMERS. DOES HE PROVIDE ANY EVIDENCE THAT THEY WERE NOT?

A. No. Mr. Schlissel notes that the location of the Redhawk units allowed them to serve both APS and export markets. He comments also that the West Phoenix units also could either export to other markets or would free up other units for export. This is simply prudent planning. If APS itself had built these units, it similarly would have sited them so that surplus off-peak energy could be sold to export markets. It would have been very foolish indeed to site these units such that economic energy was "bottled in" and unable to reach a market when not needed to serve native load. But the location of these PWEC units within the APS service territory is nevertheless significant because they could be used to serve APS without additional wheeling costs and could be dispatched efficiently with existing APS units. It also is significant that PWEC likely would not have constructed West Phoenix CC-4 (a unit of suboptimal size and configuration for merchant purposes) but for APS' critical reliability need for generation to be built quickly within the Phoenix area. My understanding is that the plant configuration was selected because it could be sited and built quickly.

Q. BEGINNING AT PAGE 22, MR. SCHLISSEL DEVELOPS AN ARGUMENT THAT HAD PWEC BEEN BUILDING TO MEET APS' NEEDS, IT WOULD HAVE BUILT FEWER COMBINED CYCLE UNITS AND MORE PEAKERS. DO YOU AGREE?

A. No. This is the same issue that I just addressed. If APS were an "island" utility, as some utilities were many years ago, then I would agree. It was not. It was a utility in the middle of a region that was short of economic energy. It has very strong transmission ties to energy-deficit subregions. Since the projected margins from selling surplus energy to others away from the APS peak were more than enough to cover the additional cost of a combined cycle unit relative to a peaker, the plan to build combined cycle units in preference to peakers was prudent both from the perspective of a vertically-integrated utility and from that of an unregulated GENCO.

Q. AT PAGE 23, MR. SCHLISSEL CITES AN OCTOBER 31, 2001 STUDY THAT INDICATES THAT REDHAWK 3 AND 4, HAD THEY BEEN BUILT, WOULD BEST BE BUILT AS PEAKING UNITS. EVEN IF TRUE IN OCTOBER OF 2001, DOES THIS DEMONSTRATE THAT IT WAS IMPRUDENT TO BUILD 1,600 MW OF COMBINED CYCLE UNITS TO SERVE APS' NEEDS?

A. No. All that this shows is that by the end of October 2001, the facts had changed. When the PWEC Arizona units were planned and committed, California still had not allowed construction to begin on any combined cycle units. Little was being built in the West outside of California. The Western energy debacle of 2000-2001 finally caused California to begin permitting units in the winter of 2000-2001 and caused entrants to begin building significant numbers of combined cycle units in the Desert Southwest and the Northwest. As this occurred, the proportion of hours in which the marginal unit would be a high heat rate unit shrank. Hence, the tradeoff between combined cycle units and peakers had shifted in late 2001. Also relevant is the fact that PWEC itself had built about 1,600 MW of additional combined cycle capacity. From the perspective of its ability to supply a balanced portfolio, to APS or elsewhere, the fact that the PWEC Arizona assets were predominantly combined cycle made peakers incrementally more attractive. Moreover, since October 2001, gas prices have increased substantially, thus favoring again the higher-efficiency combined-cycle units.

Q. LASTLY, MR. SCHLISSEL POINTS TO APS' 2003 RMR STUDIES AND FORECASTS OF THE PWEC UNITS' CAPACITY FACTORS TO SUPPORT THE PROPOSITION THAT AN APS-CENTRIC PORTFOLIO SHOULD HAVE INCLUDED FEWER COMBINED CYCLE UNITS AND MORE PEAKERS. DO YOU AGREE?

A. No. Regarding the RMR hours, Mr. Schlissel himself points out that the West Phoenix units could export outside of the load pocket, and outside of APS, when not needed for reliability purposes. Siting the units in the load pocket solved the reliability problem without compromising the economics of the units for APS. Regarding the projected capacity factors of the units, I have two observations. The first is that the economic crossover between peakers and combined cycle units generally is at a capacity factor of 20-30 percent. That is, if anticipated capacity factors are higher, the additional cost to build combined cycle units is economically justified. In the APS planning data cited by Mr. Schlissel, only West Phoenix 4, with a capacity factor of 26 percent over the period, fits into this range. As noted earlier, the unit is a special case from the perspective of why it was built. Second, again, the facts as seen today are not the same as when the units were planned and committed. The study that Mr. Schlissel relies on is a 2003 study. Even if it supported, as it generally does not, a hindsight view that a more peaker intensive mix would be more economic, this has no relevance to the prudence of the mix decision when it was made. As I have discussed, at that time, the Western market was and appeared to be continuing to be deficient in economic capacity. Lastly, APS informs me that CTs likely could not have been built in the Valley as a result of air permit restrictions. Moreover, its analysis of a more peaker-intensive resource plan does not support Mr. Schlissel's supposition that such a resource plan would have been cheaper than rate-basing the PWEC Arizona units

Q. PLEASE TURN NOW TO DR. KALT'S TESTIMONY. WHAT IS THE ESSENCE OF DR. KALT'S POSITION ON THIS ISSUE?

A. Dr. Kalt devotes only two pages to this issue, which he testifies is a "red herring" in any event (page 15, line 13). Apparently, the distinction that he makes is that, irrespective of PWEC's intentions to secure APS' load, it did not originally anticipate doing so at cost of service prices. I agree that this was true, at least until the prospect of reregulation raised its head during the Western energy crisis. I do not understand, however, why he believes that this is somehow relevant. The then- effective decision that APS' load should be served at market prices (from 2003 onward) was made by the Commission and since has been effectively rescinded, at least with respect to pre-existing APS generation and contracts. The fact remains that PWEC built the plants in the places and on the schedule required to secure APS' load. Yes, under the Electric Competition Rules, the expectation was that the load would be served at market prices. However, PWEC properly was very concerned that APS would be able to meet load reliably and at reasonable prices during periods of market instability or shortage.

It is easy for Dr. Kalt to opine that PWEC would or should have sought maximum advantage from its assets and to allege that this was its duty to its shareholders. However, as someone who has devoted a significant fraction of his career to regulated utility issues, Dr. Kalt knows full well that because PWEC was an APS affiliate, Pinnacle West could not cavalierly ignore the effects of the burgeoning Western energy crisis and what it portended on APS' ratepayers. The fact was that PWEC (assuming the Commission-mandated asset transfer had taken place) could self-supply most of APS' requirements, whether by bilateral agreement or through a competitive bid, was a powerful hedge against the kind of meltdown that affected larger and stronger utilities in California – and the effects on both shareholders and ratepayers.

PG&E and SCE also had very substantial merchant subsidiaries, far larger than PWEC, even with the APS generation. However, their assets were principally outside the WECC and could not be used to ensure either reliability or reasonable costs to their native load customers. While these affiliates of PG&E and Edison were quite profitable in 2000-2001, this did not save their utility affiliates from severe financial difficulty, even bankruptcy, nor from incurring high costs for which their ratepayers will pay for many years to come.

Indeed, California teaches yet another, still more direct lesson about "shareholder value" when a major part of the Company is subject to regulation. Under the California scheme of regulation, PG&E and SCE were to sell to the market from their remaining (until divested) fleets of generation, and their regulated distribution and supply operations were to buy from the PX and ISO markets at market prices. The profits on those sales were to be the primary basis for recovering stranded costs. During the 2000-2001 period, the utilities made very substantial profits on the "merchant" generation that still was part of the regulated company. When the time came to clean up after the mess, the CPUC plucked out all of those profits, notwithstanding the prior arrangements, to offset a major portion of the losses suffered by the fully regulated distribution and supply operations.

Q. DR. KALT PROFFERS EXHIBIT JPK-6 TO SUPPORT THE PROPOSITION THAT THE PWEC ASSETS WERE BUILT TO SELL INTO THE WHOLESALE MARKET, AS OPPOSED TO PROVIDE

ENERGY AND CAPACITY SECURITY TO APS. THE EXHIBIT CONSISTS OF SUMMARIZATIONS OF VARIOUS PWEC PUBLIC DOCUMENTS FROM 1999 AND 2000. IS THERE ANYTHING IN THAT EXHIBIT THAT YOU HAVE NOT ALREADY RESPONDED TO IN DISCUSSING THE TESTIMONY OF OTHER WITNESSES?

A. No. These are similar to, or identical to, similar documents relied on by Ms. Jaress and Mr. Schlissel and my rebuttal would merely be cumulative. Like the documents I already addressed, they either are irrelevant or actually support the conclusion that the PWEC Arizona assets were constructed primarily to serve APS' needs.

IV. REBUTTAL TO OTHER ASPECTS OF DR. KALT'S TESTIMONY

Q. MOVING BACKWARD TO DR. KALT'S "PUBLIC POLICY" TESTIMONY BEGINNING AT PAGE 13, DO YOU HAVE ANY COMMENTS?

A. Yes. Dr. Kalt's basic thrust is that when a utility is a monopoly provider of power and related services to native load customers, it is important that regulators assure that its decisions are prudent. He also says that particular care needs to be taken to assure that self-dealing with respect to unregulated affiliates is on the terms that would have been expected absent affiliation. I generally agree with these positions.

He goes on, however, to (in effect) define prudence as a question of whether the acquisition was a good business decision at time the assets are acquired and inclusion in rate base is sought. As I testified earlier, this normally is appropriate. I caution, however, that when a utility builds assets, the key decisions and actions are evaluated with respect to what was known or reasonably knowable at the time decisions are made or actions taken, not at the time that ratebase inclusion is sought. The perspective from the time that ratebase inclusion is sought makes use of hindsight that is impermissible and universally condemned (including in A.A.C. R14-2-103) in prudence investigations.

Dr. Kalt's position is that the relevant decision to be evaluated is the decision in 2003-2004 to acquire and rate-base the PWEC Arizona assets. However, this ignores the specific and quite unusual circumstances of the PWEC Arizona assets, which circumstances I and other witnesses discussed at length in both our direct and rebuttal testimonies. In so doing, he would simply side-step the historical prudence analysis that we provided, and make the issue one of whether the acquisition is prudent today with hindsight. While I understand that this is his position on what the Commission should do, it is not appropriate. The Commission should concur with APS that it is appropriate to view the PWEC decisions to build the assets as if they had been made by or on behalf of APS.

Q. APART FROM DISPUTING THAT THE PWEC ARIZONA UNITS WERE PLANNED AND CONSTRUCTED PRIMARILY TO SERVE APS, OR THAT THE ACQUISITION SHOULD BE EVALUATED BASED ON THE PRUDENCE OF PLANNING AND CONSTRUCTION, AS IF THOSE HAD CONTINUED TO BE PERFORMED BY APS AS A VERTICALLY-INTEGRATED UTILITY, WHAT IS THE SUBSTANCE OF DR. KALT'S TESTIMONY?

A. Dr. Kalt concludes that acquiring and rate-basing the PWEC Arizona assets is not in APS' customers' interest. He concludes that it will raise rates without commensurate benefits, unduly favor PWEC over other generators and force APS' customers to bear inappropriate risks.

Q. WHAT EVIDENCE DOES HE PRESENT TO SUPPORT THE CONCLUSION THAT THE ACQUISITION WILL RAISE RATES WITHOUT COMMENSURATE BENEFITS?

A. Dr. Kalt relies first on the observation that rate-basing the units will increase rates in the near term. He performs no economic analysis, as such, to support the assertion that subsequently lower costs attributable to rate-basing the PWEC assets now will fail to provide a commensurate present value benefit. Instead, he argues that if future benefits were indeed sufficient to make the transaction attractive to ratepayers, Pinnacle West would not have offered to enter into it. He also relies on an inappropriately defined insurance analogy, and on data purporting to show that APS would have an unusually high share of its load hedged by ownership of generation.

Q. DOES THE FACT THAT THE ACQUISITION WILL IMPACT RATES IN THE NEAR TERM DEMONSTRATE THAT IT IS NOT IN THE BEST INTERESTS OF RATEPAYERS?

A. Certainly not. Acquisition of any significant new generating plant almost always increases revenue requirements in the near term simply because of how such revenue requirements are calculated under traditional ratemaking. This was true for Arizona utilities' other major generating stations for at least the past few decades and for virtually any new, major generating station anywhere. Schedule WHH-1RB illustrates the fact that new plant generally will have several years before its capital cost is below the average embedded cost of the generating fleet and several additional years before it is less expensive on a cumulative net present value basis. In the example, the technology is constant; new generating plants increase in cost with inflation. Ratebase declines with straight-line depreciation, here assumed to be on a thirty-year life. Complications such as property tax and accelerated tax depreciation are ignored for simplicity and would not affect the conclusion. As the example shows, it can take up to 15 years for the embedded cost of the new plant to be no higher than for the fleet as a whole. If load were growing less fast, it would take longer still.

Q. WHAT IS YOUR RESPONSE TO THE ARGUMENT THAT PINNACLE WEST'S VERY OFFER TO HAVE THE PLANT RATEBASED NECESSARILY BELIES THE ASSERTION THAT RATE-BASING IS IN THE APS CUSTOMERS BEST INTERESTS OVER THE PLANTS' LIFE?

A. The argument is unanswerable in part (since it is a tautology), but it is also wrong. Dr. Kalt's premise is that PWEC would not offer to transfer the units at cost unless the facilities were believed to be uneconomic, over their lifetime. His logic is that Pinnacle West can maximize its total returns, assuming that the PWEC Arizona assets are in fact worth more than book value, by retaining them in PWEC. Of course, this would raise APS' costs, but Pinnacle West should, he argues, be indifferent since these higher costs would be recovered through cost of service ratemaking. An unstated and wholly illogical assumption in his position is that any transaction that PWEC would enter into with APS would be necessarily against APS' interests, including, for example, the Track B contract. Indeed, the same logic suggests that any transaction entered into by anyone with anyone is only done on the belief that it is a bad deal for the counterparty. Dr. Kalt takes this one step farther still: his whole "demonstration" that rate-basing is a "bad deal" for ratepayers is PWEC's supposed belief. In fact, real world transactions occur largely because they are "win-win", not because one party is taking advantage of the other.

It simply is not the case that Pinnacle West's willingness to enter into this transaction "proves" that it is a bad deal for APS' ratepayers, or even that

Pinnacle West management believes that it is. Neither Dr. Kalt nor I can speak for Pinnacle West management as to why they are willing to sacrifice long-term value by transferring these assets at book value despite believing that they are worth no less than depreciated book cost and most likely, significantly more. Quite properly, Pinnacle West's motivation is explained by Jack Davis in his direct and rebuttal testimony. Dr. Kalt purports to infer, as an outsider and economist, that it necessarily is true that management's sole reason for the rate base offer is that it believes that the PWEC assets are uneconomic. However, I can think of several other reasons (as an outsider and economist) why Pinnacle West might offer to rate base economic assets. I am aware that the management members have had their entire careers in the regulated utility industry, indeed primarily at APS. They might well be prepared to sacrifice some anticipated value to return to a more familiar model. A second possible explanation is that as a stand alone entity, PWEC is ill-positioned financially to absorb the near-term book losses of the currently depressed power market; Pinnacle West would then feel compelled to sacrifice long term value to solve the near term liquidity problem. A related explanation is that, due to the Track A decision, it lacks the critical mass of generation, and in particularly the diversity of fuel types, old and new plant and contracted and uncontracted plant necessary to survive the short run depression in the market. Pinnacle West would then reasonably feel compelled to again sacrifice long term value to solve this near term liquidity problem. A third explanation harkens back to the role PWEC has served as a hedge against APS market exposure. Pinnacle West could reasonably conclude that unless it offered APS, and by extension this Commission, a clear opportunity to acquire these assets at cost – which is how they would have been treated if constructed by APS in the absence of the Electric Competition Rules – any subsequent detriment to APS and its customers and corresponding gain to PWEC (as posited by Dr. Kalt) would not sit well with either regulators or APS customers. The former could take regulatory action against APS while the latter could either leave for competitive suppliers or further spur regulators. In short, Dr. Kalt's assumption that rate of return regulation would have fully protected APS against higher costs, while PWEC prospered, is unproven.

My point simply is that one cannot assume, as Dr. Kalt has done, that the sole explanation is that Pinnacle West actually believes that the assets are worth less than their depreciated book value.

Q. AT PAGE 17, DR. KALT QUOTES FROM YOUR TESTIMONY TO SUPPORT HIS ARGUMENT THAT THE ASSETS ARE NOT WORTH THEIR COST, CITING YOUR DIRECT TESTIMONY THAT, IF THE PWEC SALE IS NOT ACCEPTED, APS WILL NOT BE ABLE TO COUNT ON THE AVAILABILITY OF THE PWEC ASSETS AFTER EXPIRATION OF THE TRACK B CONTRACT. DID THIS PORTION OF YOUR DIRECT TESTIMONY IN FACT REFUTE EITHER THE "APS-CENTRIC" NATURE OF PINNACLE WEST'S ASSETS OR THAT THE ASSETS ARE WORTH MORE THAN BOOK VALUE?

A. No. Prudent management, having twice had offers to dedicate the PWEC assets to APS load at cost rejected, would not (or at least in my opinion should not) leave these assets uncommitted in order to offer them to APS a third time. Even the most smitten suitor eventually learns to quit proposing. Moreover, while the loss of value to Pinnacle West from selling the assets at book value may be relatively small at present (due to the Track B contract and depressed near term prices), the loss in value to PWEC and Pinnacle West in 2007 is likely to be unacceptably high. PWEC will have, of necessity, mastered merchant trading functions. So the opportunity cost of selling the assets at book would be higher and the motivation lower, if not non-existent.

Q. AT PAGE 18, DR. KALT DISCUSSES YOUR TESTIMONY CONCERNING THE LIKELY STATE OF POWER MARKETS AT THE EXPIRATION OF THE TRACK B PWEC CONTRACTS. WHAT IS THE NATURE OF HIS REBUTTAL?

A. In salient point, my testimony was that I, as well as the California ISO and the California Energy Commission, expect that the supply demand balance in the WECC to tighten severely by 2005-8. History, not merely in the WECC but elsewhere, teaches that this is likely to lead to shortage pricing. Indeed, only if short-term prices are substantially higher than today (or higher priced long term contracts offered) will additional merchant facilities be built. For APS to go to the market, either in 2007 or before, to buy thousands of MW of capacity for contracts beginning then would prove very expensive. As Mr. Bhatti testifies, this is what both the results of the recent RFP and the Company's market modeling show. More generally, and irrespective of the timing of price spikes, new generation will be built only if revenues are expected to be at least high enough to pay a risk-adjusted market rate of return on merchant investment. Hence, market prices will have to be at least high enough to cover the higher returns on new and undepreciated cost of plants similar to the PWEC Arizona generation.

Dr. Kalt's sole response is the same tautological argument just addressed: that if PWEC really believed this market forecast, it would not be willing to sell the plants at book value today. In this case, Dr. Kalt's argument is still more clearly wrong. In view of depressed near term prices, the plants certainly will be more valuable in the future than today, and book value will be less. Hence, even if Dr.

Kalt were correct that the willingness to sell at book value today somehow "proves" that PWEC believes the plants are not worth their book value today, this tells us nothing about the relative worth of them in 2007. Whatever their worth today, their value in 2007 will be significantly higher.

Q. BEGINNING AT PAGE 22, DR. KALT DISCUSSES THE TRANSACTION AS A FORM OF INSURANCE AND INTRODUCES EXHIBIT JPK-3, WHICH PURPORTS TO SHOW THAT THE INSURANCE POLICY, INSURING AGAINST HIGH FUTURE PRICES, WILL COST $1 BILLION IN NET PRESENT VALUE. IS THIS A VALID ANALYSIS?

No. It is both wrong and highly misleading. It is true, of course, that owning these plants creates a natural hedge against volatile market prices. However, this hedge is merely an additional source of value, not the primary source of value arising from plant ownership. The payment stream shown in the exhibit, from which he calculates his net present value, is not a set of "insurance" payments but rather is the cost of buying the PWEC Arizona plants – i.e. the revenue requirement associated with their fixed costs. Dr. Kalt would portray this as an insurance payment stream; but for example, my homeowner's insurance covers the risk of fire and storm damage – it does not pay for the house. Conversely, the mortgage is not insurance; the payment stream to buy the house buys housing services, not fire insurance.

In this same fashion, buying these assets buys "generation services", the right to dispatch the plant at its variable cost. The fact that these variable costs will be below market prices is not a "risk" to be insured against, but a principal source of value from owning this (or any other) generating plant.

Q. AT PAGES 24 AND 25, DR. KALT DISCUSSES THE MARKET RISKS THAT APS WOULD TAKE ON IN MARKETING THE EXCESS OFF-

PEAK ENERGY THAT THE ACQUISITION OF THESE PLANTS CARRIES WITH IT. DO YOU HAVE A RESPONSE?

A. Dr. Kalt is, of course, correct that APS would bear the risks and rewards for off-system sales from these plants. It would have the same, if not more, risk if it bought a plant's output under a PPA from Dr. Kalt's clients. Assuming that net sales proceeds flow through to customers, he is correct that this puts customers "in the business" of selling wholesale energy. Of course, APS has for a very long time sold off-peak energy into the market. At some times, the profits from this have been very high.

While I agree that this is a consequence of APS owning these facilities (or any other plants that sometimes produce energy not needed to meet native load), I do have two observations on Dr. Kalt's testimony. First, as noted above, this risk is not limited to owned plants. A common form of contract is a dispatchable unit contract. In such a contract, the buying entity, generally a utility, has the exclusive contractual right to take all economic output from the plant. If the output exceeds the load of its customers in some hours, it then is "in the business" of selling this surplus to the market. A tolling agreement is another common form of contract that differs only in that the buyer procures fuel. Yet another form of contract that results in the buyer having energy to sell in the wholesale market is a "slice of system" contract, under which the seller must deliver and the buyer must take a fixed proportion of the sellers' output. In short, there is nothing peculiar or inappropriate about a utility taking on marketing responsibility for selling surplus energy into the market. Nearly all utilities do so. Thus, all new generating facilities increase a utility's marketing role, as do many popular forms of third party contracts.

Second, at page 25 lines 6-13, Dr. Kalt states that the ratebase costs (identical to his "insurance premium") that in some measure supports the ability to produce energy for sale in the wholesale market are large relative to the uncertain value of those sales. Of course, the fixed cost of the plant is principally to support native load, not off system sales. Further, at lines 13 to 15, he faults Mr. Wheeler for not pointing out that the "losses associated with the unused excess capacity would also flow through to APS ratepayers." However, since Dr. Kalt already has notionally allocated <u>all</u> of the fixed costs of the facility to off-system sales in observing that they are high relative to likely off-system sales profits, there are no further "losses" to be measured. Dr. Kalt is double counting the same costs. In fact, he is triple counting, since these same costs are used as his "insurance premium" for native load.

Q. AT PAGES 31 AND 32, DR. KALT DISCUSSES THE EFFECT OF THE ACQUISITION ON THE EXTENT TO WHICH APS IS VERTICALLY INTEGRATED THROUGH OWNERSHIP OF GENERATION. HE INTRODUCED EXHIBIT JPK-10 WHICH PURPORTS TO SHOW THAT APS ALREADY IS ABOVE AVERAGE IN VERTICAL INTEGRATION RELATIVE TO OTHER WECC INVESTOR-OWNED UTILITIES, AND WOULD BECOME STILL MORE SO. WHAT POINT IS HE MAKING?

A. He doesn't really say. I think that the inference that he would have the Commission draw is that, whatever the virtues of vertical integration, APS already has enough of it. I note that Mr. Bhatti's rebuttal testimony addresses the factual validity of the exhibit and the conclusions to be drawn from it. As Mr. Bhatti shows, once double-counting of PWEC units, inclusion of non-APS units operated by APS, and Dr. Kalt's failure to take into account reserve margin requirements are taken into account, APS' degree of vertical integration is far from extreme, with or without the PWEC Arizona assets. I am frankly fascinated that he introduced Exhibit JPK-10. The four least vertically integrated companies are SDG&E, Southern California Edison, Pacific Gas & Electric and Nevada Power. Each of them was absolutely hammered as a result of their "short" position (i.e., their exposure to power markets) in 2000-2001. Most of the other below average companies were quite adversely impacted. Conversely, none of the heavily integrated companies (with the possible exception of Northwest hydro companies affected by the drought) suffered materially and some prospered.

Thus, while Dr. Kalt may have intended to show that APS would not benefit from further vertical control over generation, the Exhibit that he sponsors carries the opposite message.

Q. BEGINNING AT PAGE 32, DR. KALT DISCUSSES THE ISSUE OF VERTICAL MARKET POWER. DO YOU AGREE WITH DR. KALT'S ASSERTION THAT THE ACQUISITION OF PWEC IS AN EXERCISE OF MARKET POWER?

A. No. First of all, Dr. Kalt is severely stretching the definition of vertical market power almost beyond recognition to extend it to the acquisition of generation by a regulated load serving entity. Normally, the concern about such acquisitions (which is itself generally ill-founded) is that large load serving entities can exercise monopsony (monopoly buyer) power, which is quite different from the exercise of vertical market power[1]. Vertical market power is using the control of essential facilities, or of a monopoly position more generally, in one line of business to disadvantage competitors in a related business. As the quotations that Dr. Kalt supplies indicates, the principal concern over vertical market power in

[1] Just as the exercise of monopoly power necessarily requires that the monopolist artificially reduce supply in order to increase prices, the exercise of monopsony power necessarily requires that the monopsonist artificially

the electricity industry has to do with the use of control over wires to deny market access to competitors on even-handed terms.

Here, the supposed issue is that APS as a buyer is unfairly favoring its own affiliate. Even if true, and it is not, this is no more disadvantageous to competitors that it would have been if APS had built the PWEC assets in the first place. This illustrates that the real issue is prudence, whether defined historically or currently. The Commission should not be confused into treating what is really a prudence issue as a market power problem.

Dr. Kalt makes the relatively novel argument that APS' vertical market power is demonstrated by its supposed ability to sell its output from its controlled facilities or contracts at above competitive prices. He treats this as evidence that APS is not a competitive retailer. He avers that if it were, it would not be able to pay and pass on above market prices for PWEC output. There are many infirmities to this line of reasoning, not the least of which are the oversight of this Commission and the risk of losing customers to competitors. Indeed, ACPA's members are potential alternative suppliers. However, the principal infirmity, is that it is circular reasoning. Dr. Kalt assumes, without evidence (other than the tautology that I addressed previously), that the PWEC power is being sold at above a competitive price and concludes that since APS is buying at a non-competitive price that it must have vertical market power. I can only assume that Dr. Kalt's argument is made for the sole purpose of invoking the mantra of "market power." He could more easily and straightforwardly have

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reduce demand in order to drive down prices. Load serving utilities must serve their customers' loads and cannot reduce demand. For this reason, they cannot exercise monopsony power to affect market prices.

simply said that he thinks that the proposed acquisition is an above market transaction. True or not, this has nothing to do with alleged "market power."

Q. THE LAST SECTION OF DR. KALT'S TESTIMONY DISCUSSES THE IMPACT OF THE PROPOSAL, IF ACCEPTED, ON THE COMPETITIVE WHOLESALE MARKET. HE ARGUES THAT IT WOULD HAVE A CHILLING EFFECT ON THE WHOLESALE POWER MARKET BY DENYING TO OTHERS THE RIGHT TO COMPETE WITH PWEC. PLEASE COMMENT.

A. I have several observations. First of all, by canceling the transfer of the APS generation assets to PWEC, the Commission already has taken substantially more generation out of the competitive market that is represented by the PWEC Arizona assets. If merely shrinking the amount of merchant generation and the size of the net short position of the state's utilities were a major issue, it presumably would not have done so.

Second, as Dr. Kalt's Exhibit JPK-10 shows clearly, there are a number of generation short utilities in the WECC. The removal of 1700 MW of generation and of an equivalent amount or retail load from the market will hardly be noticed, let alone be fatal.

Third, any time that a utility enters into a transaction with anyone, it denies to other competitors the right to serve that same load. This is true of contracts with third parties as well as outright purchases of generating facilities. If, for example, APS had instead contracted with the Gila plant for 1700 MW, all other competitors would similarly be "frozen out" from serving that 1700 MW.

Fourth, as discussed by Mr. Bhatti, competitors were not frozen out. However, what they have offered is not more economic than the purchase of the PWEC assets. Further, APS remains generation short and will continue to provide a growing market for competing generators. It is notable here that, both in the RFP and in the Track B solicitation, existing competitive generation was unable to meet APS' needs without it first relying on the PWEC Arizona assets.

Dr. Kalt does not actually focus on supposed harm to competitors, but to the alleged unfairness of an alleged "bailout" of PWEC. Apart from the fact that any transaction would remove APS load from availability to competitors (and simultaneously remove a like amount of supply with whom they otherwise would have to compete), there is no impact of the supposed "bailout" (which this is not) on PWEC's or APS' competitors. The wholesale price of power is set by the interaction of supply and demand in the wholesale market. Removing like amounts of supply and demand has no effect on the market price. Even if, as he alleges, the asset transfer helps PWEC, helping PWEC does not hurt others. Once again, Dr. Kalt is confusing prudence with a competition issue. From the perspective of the supply and demand balance in the wholesale market, a "bailout" in the form of APS paying too much for PWEC power would injure competitors only if, absent the transaction, the PWEC Arizona assets would: 1) be shut down and removed from the market and 2) have a sufficient market impact to matter. If both conditions were met, this would, at least marginally, tighten up supply and demand balances, thereby also marginally contributing to the ability of PWEC's competitors to raise prices. However, as we have seen with bankrupt merchants and assets that have been turned over to banks, assets that can cover their going forward costs in the market are not removed from the market. Hence, a competitor would not be injured by the supposed fact that APS is paying too much for PWEC assets. The only "injury" would arise, if any, from the fact that APS was purchasing power from someone other than it, which is the injury any competitor realizes when it loses the competition, an injury that is independent of who the winner is and the terms upon which the winner has prevailed.

V. VALUATION OF THE PWEC ARIZONA ASSETS

Q. STAFF AND SOME INTERVENOR WITNESSES CLAIM THAT THE PRIMARY ISSUE THAT NEEDS TO BE ADDRESSED IN DETERMINING WHETHER THE PWEC ARIZONA ASSETS SHOULD BE INCLUDED IN APS' RATEBASE IS WHETHER THE PURCHASE IS PRUDENT AT THE CURRENT TIME. DO YOU AGREE?

A. No, for reasons I have discussed at length. However, in the event that the Commission determines that it is the current prudence of the asset purchase, as opposed to the prudence of decisions to construct the units when made, is relevant, then the relevant evidence concerns the prudence of the purchase in 2004 or early 2005.

Q. UNDER THAT CIRCUMSTANCE, HOW SHOULD PRUDENCE BE DETERMINED?

A. Prudence should be determined according to Commission Regulation A. A. C. R14-2-103. That regulation states a presumption that the investment is prudent that only can be set aside by clear and convincing evidence. The standard of prudence itself is that the decision is reasonable given the facts available at the time.

Q. WHAT IS THE PRIMARY FACT THAT INTERVENOR AND STAFF WITNESSES SUGGEST SHOULD BE THE FOCUS OF THE PRUDENCE INQUIRY?

A. Fundamentally, the question that they propose should be the focus is whether the purchase is a "good deal" for APS' ratepayers. I interpret this as meaning whether the PWEC Arizona assets are worth the purchase price. In turn, this question would require an analysis of the value of the assets, which then could be compared to the purchase price.

Q. WHAT ARE THE GENERALLY ACCEPTED MEANS OF ASSET VALUATION?

A. There are three basic methods for valuing assets: cost basis, comparable transactions and discounted cash flow.

Q. WHAT IS THE COST BASIS?

A. The cost basis usually is called "reproduction cost new less depreciation." Reproduction cost is the cost of replicating the asset. In the case of the Redhawk units, for example, it is the cost of building a GE Frame 7F combined cycle plant. A sometimes alternative to reproduction cost is replacement costs. This is the cost of building a facility or acquiring an asset with similar utility. For example, if the plant in question is of an antiquated technology, replicating it is not a particularly useful key to value. Rather the issue is, what is the cost of a modern type of facility that will do the same things?

Q. PLEASE EXPLAIN THE COMPARABLE TRANSACTION METHOD OF VALUATION.

A. This is the one familiar one to most people, since it usually is used in residential real estate appraisals, including tax appraisals. The appraiser looks for recent transactions of a like type in the same neighborhood. If such transactions can be found, then they are "comparable" and form the basis for appraising the house. It is not always so easy; there may be similar transactions in neighborhoods with higher or lower property values and transactions of more or less valuable property in the same neighborhood. The appraiser may need to piece together a comparable from components. Still, the concept is to find market transactions of like properties to use in setting the value.

Q. WHAT IS THE DISCOUNTED CASH FLOW METHOD?

A. This method, sometimes called the income method, is most commonly used for rental properties or for businesses. It is virtually the sole method available for "going concern" businesses. The concept (though not the execution) is simple enough. The appraiser forecasts all cash flows (e.g., revenues, expenses, capital improvements, taxes interest and principle payments on debt, and so forth) and takes the net present discounted value of them to arrive at the valuation.

Q. CAN ALL OF THESE METHODS BE APPLIED TO VALUING THE PWEC ARIZONA ASSETS?

A. Yes, with varying degrees of reliability.

Q. IS THERE AN ESTIMATE OF THE REPLICATION OR REPLACEMENT COST NEW LESS DEPRECIATION ON THE RECORD?

A. Mr. Bhatti provides an estimate of replacement cost. That analysis shows a clear economic benefit from rate-basing the PWEC Arizona units. He also provides revenue requirements analyses based on a variety of replacement scenarios that I will note in discussing DCF valuations. Mr. Salgo's analysis replacing the PWEC units with 1,700 MW of replacement capacity in 2007 could be thought of either as a DCF analysis or a replacement cost analysis. For my rebuttal purposes, I treat it as the latter.

Q. IS THERE TESTIMONY ABOUT COMPARABLE TRANSACTIONS?

A. Not to the best of my knowledge. Certainly, Staff and intervenors have presented no testimony valuing the PWEC Arizona facilities based on comparable transactions.

Q. HAVE YOU SOUGHT TO ANALYZE A COMPARABLE TRANSACTIONS BASIS FOR VALUING THE PWEC ARIZONA ASSETS?

A. Yes. I have employed four screens in searching for comparable transactions data. The first is that the transaction must be in the WECC. This is necessary because regional power markets have seen substantial differences in the market price of power and, in some cases, in the ability of merchant power plants to access markets unimpeded by transmission constraints. In particular, the very substantial over-building in the Southeast Reliability Council (SERC) and in the Texas interconnection region (ERCOT) have severely depressed prices there. Conversely, there is relatively little price separation within the WECC; to at least a first approximation, all similar plants sold in the WECC should be useful comparables.

Second, I have restricted the search for comparables to modern gas units, particularly combined cycle units. Materially older gas steam and even combined cycle units are substantially less valuable. Other units that have changed hands, for example, wind generation, are not readily comparable.

Third, I have restricted my search to sales occurring well after the Western power crisis. Transactions occurring during or soon after the crisis are arguably affected by expectations during that time.

Fourth, for purely practical reasons, I have only used transactions for which pricing data are available. This excludes a number of potentially comparable sales for which transaction terms are confidential. Inherently, I cannot compare the sales price of the PWEC Arizona units to the sales price of units for which price data are unavailable.

Q. WHAT UNITS HAVE YOU BEEN ABLE TO FIND THAT MEET THESE CRITERIA?

A. The most recent transaction is Edison International's purchase of the Mountainview combined cycle facility in California. This is a 1056 MW (all capacity figures are intended to be Summer Maximum Dependable Capacities, rather than nameplate capacities) two-unit gas combined cycle unit, similar to Redhawk and West Phoenix 5. The deal is pending but all key approvals have been received. The unit does not yet exist; the CEC database lists it as 15 percent complete. The acquisition cost is confidential. However, Edison has stated that the cost to complete it is $700 million. It is not clear whether this includes the cost paid to the seller or not. Hence the cost to Edison is at least $663/kW. Note also that while this plant will be owned in a special purpose subsidiary, the output will be sold to the utility on a cost of service basis.

A second comparable plant is the Frederickson plant. Puget Sound is buying the half of the plant that it does not already own. This is another modern combined cycle plant, located in Washington state, but only 249 MW, smaller that the Redhawk and West Phoenix 5 units and likely to be somewhat more expensive in terms of its production costs. Puget Sound is paying $73.23 million (another source gives $80 million) for 125 MW of capacity, yielding a cost of $585/kW.

A third comparable sale is the Desert Basin sale. Salt River Project is paying $288.5 million for this 529 MW MDC combined cycle unit in Arizona. This equates to $545/kW.

The remainder of the comparable transactions are of much more limited value for various reasons. Calpine paid $295 million to buy out Bechtel's 50 percent share of Delta Energy, an 840 MW combined cycle unit in California. This equates to $702/kW. This deal was signed in November 2001, about 6 months after the end of the Western energy problems of 2000-2001. Indeed, energy prices at that time where quite low compared to now due to lower gas prices.

GE Capital paid $82 million for 69 MW of a 115 MW California CT last April. This is $1,188/kw. However, as the high price suggests, it is likely that what GE was buying was a highly favorable QF contract, so I do not rely on this transaction. Similarly, Black Hills paid $1,285/kW for a 20 MW share of Harbor Cogen in California in January of 2003. Again, this appears to be non-comparable due to the existence of a QF contract.

The only other potentially comparable transaction to report is the Man Chief combustion turbine unit in Colorado. This 241 MW station was sold in November of 2002 for $127 million, a price of $527/kW. I include this transaction since it is the only peaking transaction in the region for which I have data.

Q. YOU MENTIONED THE DESERT BASIN UNIT AND INDICATED A PRICE OF $545/KW. MR.SCHLISSEL AT PAGE 18 OF HIS TESTIMONY STATES THAT THE PRICE WAS $492/KW. WHAT ACCOUNTS FOR THE DIFFERENCE?

A. Mr. Schlissel and I are using the same transaction value. The difference is that his cost per kW is based on nameplate capacity of 590 MW, whereas I am using the summer maximum dependable capacity (MDC) of 529 MW. My capacity measure is consistent with the way in which the PWEC capacity is rated. His is not.

Q. WHAT IS THE PROPOSED TRANSACTION PRICE FOR THE PWEC ARIZONA UNITS?

A. As shown below, the proposed price is the rate base amount requested in this rate case. It is approximately $526/kW.

Q. HOW DOES THIS COMPARE TO THE BENCHMARK ARMS LENGTH TRANSACTIONS?

A. The price is lower than any of the benchmark transactions.

Plant Name	Plant Type	Transaction Date	Cost ($/kW)
Delta Energy	Combined Cycle	11/01	702
Man Chief	Comb. Turbine	11/02	527
Desert Basin	Combined Cycle	10/03	545
Frederickson	Combined Cycle	Pending	585
Mountainview	Combined Cycle	Pending	663+
PWEC Arizona	Primarily CC	Proposed	526

I note also that there are proposals as part of the RFP process involving APS' purchase of plants from merchants or constructors. I have not included these proposals in my comparison since I am not privy to the specific RFP results and, in any event, am unsure of what could be disclosed.

Q. ARE THERE ANY CHARACTERISTICS OF THE PWEC ARIZONA UNITS THAT SHOULD BE TAKEN INTO ACCOUNT IN VALUING THIS TRANSACTION RELATIVE TO COMPARABLES?

A. Yes. The existence of the Track B contract should be taken into account, since APS gives up the value of that contract. I must emphasize that the value of that contract must be assessed relative to the market, not to the cost of rate-basing the plant.[2] Mr. Bhatti testifies that the projected value of the contract relative to the market for 2005 and 2006 is a small fraction of the value relative to ratebasing the plant. Adjusting the value of the PWEC Arizona units taking into account this value would be quite unlikely to change my conclusion that APS is paying no more than the market price for the PWEC Arizona units.

Q. ASSUMING THAT THE COMMISSION CONSIDERS ASSET VALUATION RELEVANT, WHAT WEIGHT DO YOU BELIEVE THAT IT SHOULD GIVE TO THIS COMPARABLE SALES ANALYSIS IN DETERMINING WHETHER THE PROPOSED TRANSACTION IS A GOOD DEAL FOR RATEPAYERS?

A. I believe that it should be given substantial weight. These arms length transactions are for similar facilities, in the same region and closely matched in time, are strong evidence of the market value of the PWEC Arizona assets.

I recognize that comparables are never perfect. Parties that oppose this transaction likely will seek to distinguish each of the comparable transactions. Nonetheless, the fact that the PWEC Arizona transaction is no more expensive

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[2] Each of the comparable valuations presumably is based on the buyers' and sellers' valuation of the plants relative to market opportunities. The only adjustment to valuation, for the PWEC assets or any other asset, is due to the fact that the asset receives more, or less, than market prices. It is for this reason that I excluded the QF transactions. The only place in which the cost of the Track B contract relative to the cost of rate-basing the plant is relevant is the DCF analysis, discussed below.

than <u>any</u> of the comparable transactions, should add to the weight accorded to this means of valuation.

Q. PLEASE TURN NOW TO DCF METHODS OF VALUATION. ARE THERE DCF EVALUATIONS OF THE TRANSACTION IN THE RECORD?

A. Yes. Mr. Bhatti's Rebuttal Testimony contains a number of alternative DCF studies that demonstrate generally that the transaction is beneficial to ratepayers even after the Track B contract is taken into account. Mr. Salgo and Mr. Schlissel also provide DCF or revenue requirements (replacement cost) studies.

Q. PLEASE REVIEW MR. SALGO'S STUDY.

A. I note first that Mr. Bhatti's testimony covers errors in Mr. Salgo's valuation of the costs associated with elimination of the Track B contract with PWEC. This includes, among others the correctness and relevance of the 2004 contract value, given the likely rate effective date implied by the schedule of this proceeding. Eliminating the 2004 value of the contract (which is not affected by subsequent inclusion of the PWEC assets in APS' rate base) and modestly reducing the gap between the contract and rate base costs in 2005-2006 has a significant effect on the cumulative losses carried forward to other years.

Second, I note that Mr. Salgo rather arbitrarily assumes that there will be an improvement in the efficiency of turbines between those in place at PWEC and the assumed 2007 replacement turbines. Since the current generation of turbines is technologically mature, this is rather unlikely. Similarly, Mr. Salgo assumes, without apparent basis, that the escalation in combined cycle construction cost will be only about 2 percent a year. However, I do not deem this to be sufficiently unrealistic to contest.

Third, Mr. Salgo appears to have used the APS' proposed cost of capital as the discount rates. This is wrong in two respects. First, it is quite inconsistent for Staff to be proposing a much lower cost of capital but basing its discount rate on APS' rate of return request. Had it used a discount rate based on its own cost of capital requirement, the future savings from the PWEC Arizona assets would have been larger.

Moreover, Mr. Salgo used a 9.04 discount rate, which is the full APS cost of capital. For quite sound reasons, the appropriate discount rate is the fully after-tax cost of capital. This is referred to as the "net-of-tax" discount rate. The calculation of this rate is familiar from, for example, the calculation of AFUDC rates. The net-of-tax discount rate includes the full cost of equity times the equity share plus the debt rate minus its associated tax shields times the debt rate. For example, if the cost of equity is 12 percent and the cost of debt is 6 percent, the tax rate is 39 percent and the capital structure is 50:50, the rate that Mr. Salgo would use is 9 percent. However, the proper weight is .5*.12 + .5*.06(1-.39), or 7.83 percent. This lower discount rate would make the long-term benefits of the PWEC rate-basing still larger. Parenthetically, this explains why, as Mr. Salgo observes at lines 21-24 of page 20 of his testimony, APS' analyses use a lower discount rate than the cost of capital.

Q. SETTING ASIDE THE ERRORS THAT YOU HAVE DISCUSSED, WHAT DOES MR. SALGO'S ANALYSIS SHOW ON ITS FACE?

A. Mr. Salgo's analysis shows that over its life cycle, the PWEC assets are lower cost than his hypothetical 2007 replacement plant, even taking into consideration his over-stated benefits from the APS/PWEC Track B contract.

His assumed improvement factor for the replacement facility makes it (rate-basing) marginally more expensive.

My understanding is that Mr. Bhatti has corrected the early year errors (but not the discount rate error) in Mr. Salgo's analysis, and shows that the PWEC plant is still more cost effective, relative to Mr. Salgo's hypothetical replacement, than is shown in Mr. Salgo's analysis on its face.

Q. **MR. SALGO SUGGESTS THAT HIS 2007 REPLACEMENT MAY NOT BE A LEAST COST ALTERNATIVE, AND THAT HENCE HIS ANALYSIS IS CONSERVATIVE. PLEASE COMMENT.**

A. This is mere assertion on his part, without any evidentiary support. The PWEC assets are the same type of assets that nearly all utilities, and non-utility generators, are building. There is no evidence to support the proposition that facts have changed so dramatically since PWEC's planning studies that led to constructing these assets that a different mix would be preferable. Moreover, as Mr. Bhatti explains, the plan that Mr. Salgo compares to rate-basing the PWEC assets is itself not feasible, primarily because APS could not reasonably manage the simultaneous construction of 1,700 MW, for which authorization has not even been sought, on sites that in some cases are not owned and/or lack needed gas and electric transmission facilities, on such an abbreviated schedule. Mr. Bhatti demonstrates that any feasible plan would, in fact, be more expensive that the plan that Mr. Salgo assumes.

Q. **AT PAGE 25, MR. SALGO TESTIFIES THAT IN THE EVENT THAT THE COMMISSION AGREES TO PUT THE PWEC ARIZONA ASSETS INTO RATEBASE, THAT REVENUE REQUIREMENTS SHOULD BE REDUCED BY $99 MILLION PER ANNUM FOR THE REMAINING DURATION OF THE TRACK B CONTRACT. DO YOU AGREE?**

A. No. Mr. Salgo's proposal is that ratepayers have their cake and eat it too. According to Mr. Salgo's Exhibit HS-2, the NPV of losses to APS from canceling the PWEC Track B contract over the four-year period when it is in effect is $350.4 million. His analysis also indicates that rate-basing the PWEC assets costs about the same as his identified alternative. Ignoring the fact that the cost of canceling the Tract B contract is overstated, on its face his analysis shows that buying and rate-basing the PWEC assets and retaining the Track B contract value would result in a $350 million lower cost to ratepayers than would his alternative plan. To propose that the purchase be conditioned on requiring a savings of $350 million relative to PWEC's market value (with a concomitant loss to PWEC) surely is over-reaching even if the rate-basing of the PWEC assets was not imbued, as it is, with significant equitable and policy considerations stemming from Track A Order.

As I testified earlier in this testimony and in my Direct Testimony, it is true that the PWEC assets would be a still better deal for ratepayers if the Track B contracts were to remain in place and the assets could be purchased at then book value in 2007. However, as Mr. Salgo recognizes, this has not been offered and is not therefore a legitimate alternative. As is shown by his own analysis (and every other analysis in this record), Pinnacle West would derive substantial negative value from such a transaction.

The whole point of doing NPV analyses is to trade off future benefits for near term costs. A deal that has a positive NPV, no matter how small, is a good deal. Mr. Salgo would have the Commission demand that PWEC both absorb the near term costs of the contract and give up the long-term benefits of earning market revenues. This ignores the finding of his own analysis, that on its face shows that rate-basing the PWEC Arizona assets is on a par with the alternative against which he tests them, even if this requires giving up the near term value of the Track B contract.

Q. PLEASE TURN NOW TO MR. SCHLISSEL'S ANALYSIS OF RATE-BASING THE PWEC ARIZONA ASSETS. WHAT DOES MR. SCHLISSEL COMPARE THE RATEBASE COSTS OF THE PWEC ASSETS TO?

A. Mr. Schlissel compares the cost of owning the PWEC Arizona assets to the cost of purchasing from the market on an annual basis. His analysis is based on data produced by APS.

Q. WHAT DOES HIS ANALYSIS SHOW?

A. His analysis shows that the cost to APS of owning the PWEC Arizona assets is considerably cheaper than buying from the market. By 2022, the cumulative NPV savings is in excess of $100 million. For some reason, he truncates his analysis at that date. In fact, the PWEC assets have a remaining life in 2022 of at least 10 years (based on a thirty year book life).

On its face, his analysis that the PWEC assets are producing annual savings to rate payers of well over $100 million and that the savings are growing rapidly. While present valuing these annual savings diminishes their cumulative value, they still are large in present value terms and it is clear that the savings in the 10 years after 2022 will create additional NPV. I have asked Mr. Bhatti to calculate the NPV of post-2022 savings. Based on the market scenario that Mr. Schlissel uses in his testimony, the savings are an additional $441 million of net present value.

Q. BASED ON HIS ANALYSIS, DOES MR. SCHLISSEL THEN RECOMMEND THAT THE COMMISSION AGREE TO RATEBASE THE PWEC ASSETS?

A. No. He chooses to ignore what should be the main conclusion of his analysis and instead focus solely on the near term costs of rate-basing the PWEC assets. According to his analysis, the assets do not produce an annual net cost benefit until 2011 or a cumulative benefit until 2020. His key conclusion is his conclusion 10 that states, effectively, that even if it could be demonstrated that the PWEC assets result in a life cycle benefit, this would not justify the rate-basing of the assets since it would be "unfair" that current customers pay higher rates to obtain future benefits.

Q. DO YOU AGREE WITH THIS ASSERTION OF UNFAIRNESS TO CURRENT RATEPAYERS?

A. Absolutely not. I have participated in a large number of plant-in-service rate cases. In each case, the comparison used to establish plant value was NPV over the plant's life discounted back to the appropriate time.[3] It is entirely appropriate to end the inquiry into value with the NPV of the assets, rather than to focus on the timing of benefits, which after all is dictated by regulatory policy, not by the characteristics of the assets. The fact that the PWEC assets will be less economic for current than future ratepayers has nothing to do with the economics of the PWEC assets themselves. As my earlier schedule shows, this is characteristic of any new utility assets given the ratemaking and regulatory accounting practices of the ACC and regulators in all states. A generating asset produces essentially level benefits for a very long time.

However, the recovery of its costs is front loaded. Current ratepayers benefit from the front-loaded cost recovery for existing assets that were disproportionately paid for by earlier ratepayers. In turn, they pay disproportionately for new assets that will benefit ratepayers in future years.

This is the way it always has been. This timing of costs and benefits is not unique to generation. Current customers similarly pay a disproportionate share of the cost of new distribution and transmission assets. Over time, a distribution circuit continues to provide the same benefit to customers, but since it depreciates, its cost to them is increasingly less.

Indeed, the phenomenon is not limited to utility assets, but to the accounting profitability of non-utility assets as well. A new commercial office building rarely will earn a full accounting profit in its early years. However, its profitability will rise as the cost of new construction increases market rents and as the depreciated value of the building falls. This "super" profit in later years compensates for the accounting losses in early years.

On a more fundamental level, Mr. Schlissel's problem is not just with regulatory accounting, but with growth in the Arizona economy and population. If Arizona were to suddenly cease to grow, current ratepayers would get a "fair" deal by Mr. Schlissel's criterion. The state would need essentially no new power plants or distribution investments. Customers would be served wholly by depreciated existing assets and, all else equal, there would be less upward rate pressure. This

[3] In prudence cases, the costs and benefits are those reasonably anticipated at the time the decisions were made. Even those witnesses and parties that proposed "economic excess capacity" standards (effectively, the cost of the plant relative to alternatives at the time rate base inclusion is sought) have focused on NPV.

is not just because of utility accounting. Arizonans also could be served by schools, highways, hospitals and so forth that were constructed at lower historic price levels and are depreciated and have their bonded indebtedness substantially paid off. While this would be better for current customers (ignoring effects of their incomes) I very much doubt that the Commission would endorse policies that stagnate economic growth in Arizona.

Q. CAN YOU EXPLAIN WHY IT TAKES A NUMBER OF YEARS FOR THE PWEC ASSETS TO APPEAR COST EFFECTIVE RELATIVE TO MARKET RATES FOR CAPACITY AND ENERGY?

A. Yes. The primary reason is utility accounting and ratemaking. Since cost of service pricing includes a return on and of book investment, the revenue requirement for the fixed cost of facilities diminishes, even in nominal terms, over time. In real (inflation adjusted) terms, it declines still faster.

There is another and less obvious reason for the relatively long time that it takes for new assets to become cost effective relative to the APS forecast of market prices. In order to understand this, it is necessary to understand how APS, and most if not all other utilities and analysts of long term electricity markets, forecast market prices.

Price forecasts are composed of forecasts of prices for capacity and energy. In the series that Mr. Schlissel is using, the capacity prices are based on long run marginal costs from 2006 onward (Schlissel, page 13 lines 18-20). In turn, long run marginal cost prices are at a level sufficient for a new generating unit coming on line in that year to fully recover its total cost (including return on investment) over its life.

If 2006 (and each subsequent year) has prices sufficient to recover the full cost of a new unit built in that year, how can it be that the prices are not high enough that the PWEC units yield current year savings until 2011? The answer lies in the time stream assumed in creating the long run marginal cost prices, in comparison to the time stream of revenue requirements.

APS' long run marginal costs used in this forecast assume a time stream of cost recovery based on levelized real costs. That is, the inflation-adjusted fixed cost recovery is assumed to be constant in real terms over the book life of the unit. In nominal (current dollar) terms, this means that the cost recovery increases at the rate of inflation. Conversely, the revenue requirement associated with the fixed cost of the PWEC unit decreases over time in nominal terms as a result of depreciation. The early year revenue requirement for a ratebased plant is above the average, whereas the early year revenue requirement for the plant setting long run marginal cost prices has a low "revenue requirement" in early years. In accounting terms, the cost of capital used for the long run marginal cost plant assumes real rather than nominal costs of capital (lower by the rate of inflation) and sinking fund rather than straight-line depreciation (sinking fund depreciation, like the principal payment on a thirty year mortgage being minimal in early years.)

It is useful to explain the underlying economic assumption governing constant real cost recovery assumed in setting long run marginal cost prices. It assumes that the facility will fail to recovery its cost of capital in the accounting sense in the early years. If one were to prepare a profit statement on the plant, it would show little profit or perhaps losses. This is not inconsistent with the real world.

A new steel mill, aluminum smelter or oil refinery selling its output at market prices generally will fail to recover its full accounting costs in early years of operation. If such plants routinely did recover their full accounting costs (including a market rate of return) from year one, it would follow that over their lifetimes, they would greatly over-recover their costs, since in later years prices will be higher (due to inflation) and capital-related costs will be less (due to depreciation). A pattern of returns that systematically yield profits in excess of the cost of capital is not consistent with market equilibrium or long run marginal costs.

From the perspective of the company owning the facility, this means that it may earn accounting returns equal to the market required rate in the early years of the investment, but only if it also has older, depreciated facilities that are earning well above market required rates on their depreciated investment base. This is true of owners of merchant generation, just as it is for owners of refineries. The difference for utilities is that it is the ratepayer, rather than the owner, that depends on this portfolio effect. Just as an oil refiner is likely to see book returns on investment decline when it brings a major new facility on line, ratepayers are likely to see an increase in rates when significant new investments come on line.

Given the different assumed time stream of capital cost recovery between the unit setting long run marginal cost prices from 2006 onward versus the PWEC units earning revenue requirements, it is not surprising that the cross-over occurs well after 2006. Indeed, if the unit setting the market price were assumed to have revenue requirements accounting, the crossover would have been in 2006, just as it was in 2007 in Mr. Salgo's analysis that assumed ratebasing replacement capacity in that year.

Notably, the NPV of units earning revenue requirements and units assumed to earn according to a levelized real time stream are, by construction, identical. Hence, the delayed "crossover" that Mr. Schlissel focuses on has nothing to do with the economics of the PWEC units and is due entirely to the way in which units setting long run marginal cost prices are assumed to recover their costs versus how regulatory accounting recovers costs.

VI. RESPONSE TO COMMISSIONER GLEASON'S LETTER OF SEPTEMBER 5, 2003 (QUESTIONS 4 AND 5)

Q. QUESTION FOUR IN COMMISSIONER GLEASON'S LETTER ASKS WHETHER OTHER STATE COMMISSIONS HAVE RULED ON INCORPORATING MERCHANT ASSETS IN RATE BASE AND, IF SO WHAT THEY HAVE DECIDED. DO YOU HAVE ANY RESPONSIVE INFORMATION?

A. Yes. I am not certain that I am aware of all such transactions, but will discuss all of which I am aware. Cinergy's subsidiary Public Service of Indiana filed to include two peaking plants previously owned by unregulated merchant subsidiaries in rate base. The Indiana state regulators approved the transaction in December 2003.

Puget Sound is seeking approval to include the 50 percent of the Frederickson generation facility that it did not own previously. According to its recent SEC Form 10-K, the Commission staff has testified in favor of the transaction and no intervenors opposed it. To the best of my knowledge, the Washington commission has not issued a final order.

Southern California Edison is seeking to gain approval to have an unregulated affiliate acquire the Mountainview project and enter into a cost-based 30 year contract with the utility to provide power to it. The CPUC approved the application to enter into the transaction and FERC has conditionally approved the application.

I am aware of other such transactions, but none in which the state commission has ruled. Ameren subsidiary Union Electric is seeking approval to purchase 500 MW of peaking facilities from an unregulated affiliated Genco. The transaction, which Ameren's 10-Q indicates will be finalized sometime this year, does not require approval by the Missouri Commission. The rate treatment of the investment will be determined in Union Electric's next Missouri rate case. There currently is a rate freeze through 2006, so there is no current venue in which the Missouri Commission could rule on rate treatment. I should note that Mr. Schlissel, who discusses this transaction, states that the Illinois Commerce Commission staff filed testimony opposing the transaction and that the application was withdrawn by Union Electric. The implication is that the two events are related. In fact, Ameren decided to transfer Union Electric's small Illinois service territory to another Illinois utility that it owns, Central Illinois Public Service. Since the acquisition of the peakers is by Union Electric, the acquisition no longer is jurisdictional to Illinois.

Ms. Jaress discusses transactions relating to a Washington utility, Montana Power and Dayton Power and Light. I have no additional information on these transactions.

Oklahoma Gas & Electric is seeking to include the McClain combined cycle unit, presently owned by NRG, in rate base. The matter currently is before FERC and is not yet ripe for state ratemaking determination. However, the state commission has supported the company's FERC application and has threatened to reduce OG&E's rates if it cannot acquire more utility-owned generation.

These are the only transactions of which I am aware that are responsive to the question.

Q. COMMISSIONER GLEASON'S FIFTH QUESTION ASKS HOW THE COMPETITIVE SOLICITATION OF POWER AS ENVISIONED BY THE TRACK B ORDER WILL BE AFFECTED IF THE APS PURCHASE OF THE PWEC ASSETS IS APPROVED.

A. The obvious impact will be that APS will need to purchase 1,700 MW less from the market than if the assets are not acquired. According to the loads and resources plans contained in Mr. Bhatti's Rebuttal Testimony, APS's net short position in 2007 is approximately 2,800 MW. Hence, the amount of capacity to be procured from external sources (including PWEC) declines to a little over 1,000 MW.

The posited reduction of 1700 MW may well overstate the reduction in the amount that could be purchased from existing or future facilities other than the PWEC facilities whether or not such facilities are rate-based.[4] Unless there are substantial transmission investments to bring additional power into the Phoenix area, or a third party builds a new plant in or near Phoenix, it still will be necessary to purchase some capacity and energy from West Phoenix.

[4] The reference to the PWEC facilities rather than to PWEC is deliberate since there is no assurance that the facilities would not be sold to a third party in the event that APS does not acquire them.

Q. WOULD THE PROCUREMENT OF THE PWEC ASSETS BY APS AFFECT THE PRICE IT WOULD HAVE TO PAY IN A TRACK B-LIKE SOLICITATION?

A. It should not materially affect the price that APS pays for energy (except, perhaps, to lower the price for RMR energy in the Valley) but could affect the price of capacity.

Q. WHY WOULD THE PRICE OF ENERGY BE LARGELY UNAFFECTED?

A. During nearly all times, the price of energy will be set by competition spanning at least the Desert Southwest, southern Nevada and southern California. Particularly with the expansion of Path 15, due to be completed well before 2007, this area will not often be constrained away from northern California and the Pacific Northwest. Hence, prices will be set in a market far larger than Arizona.

Still more important is the fact that the acquisition of the PWEC assets by APS would not change the supply-demand balance, either in Arizona or in this wider area, one iota. Whether the contract is signed or not, the PWEC assets will continue to exist and to produce power when it is economic to do so. Similarly, the other facilities in Arizona owned by unaffiliated parties, will continue to exist and will produce power when it is economic to do so. Since power prices are determined by the forces of supply and demand, the fact that neither is changed by the acquisition means that there should be little if any affect on energy prices.

Q. WHY COULD THERE BE AN AFFECT ON THE PRICE OF CAPACITY?

A. As I discussed in my Direct Testimony, by 2007 Western power markets should be back in balance or even in a shortage condition. California will remain dependent on significant imports from the Desert Southwest. To an even greater extent than today, a significant amount of Arizona capacity will be dedicated to California loads.[5]

While energy prices will be formed over a wide geographic area, capacity is inherently a more local product. Generally, in order to "count", capacity must be both deliverable and dedicated.[6] This suggests a much smaller geographic market for capacity. Given the rapidity with which loads in the Desert Southwest are growing, and the amount of capacity dedicated to exports out of the region, the capacity market could be very tight for 2007. If APS is short approximately 2,800 MW of capacity in 2007, it may face a less-than-competitive market.

Q. IN HER RESPONSE TO COMMISSIONER GLEASON'S QUESTION 5, MS. JARESS STATES THAT IF THE PWEC ASSETS ARE ACQUIRED, "THE ARIZONA MARKET AVAILABLE TO OTHER SUPPLIERS WILL BE DIMINISHED, WHICH COULD AFFECT THEM ECONOMICALLY AND COULD AFFECT THE LONG TERM VIABILITY OF SOME." DO YOU AGREE?

A. No, I do not. As I have testified, whether the PWEC assets are acquired or not has no impact on the supply and demand balance for energy and hence no impact on the competitive market price. Between now and 2007, there clearly will be no material effect since the PWEC assets are under contract during the

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5 As I discussed in my Direct Testimony, California is relying on significant capacity beyond the capacity already under contract to meet loads by the middle of the decade. Moreover, while specific plans have not been finalized and approved, the California ISO and CPUC both plan to phase in a capacity requirement that would increase the amount of capacity that would have to be dedicated to California loads.

peak summer months. Hence any effect must be subsequent. Assume that APS does not acquire the assets. It will then meet its needs from the market. If PWEC is the chosen supplier, then other suppliers will find themselves in the same position as if the assets are purchased. If PWEC is not the chosen supplier and someone else is, then that supplier presumably will only receive a competitive price. Under this scenario, PWEC replaces the chosen supplier(s) in competing in the remaining power market. This one-for-one displacement has no effect on that market and hence no effect on the competitive price. It is hard for me to see how the market, and hence competing suppliers, are affected.

Further, as I have testified, power markets should be robust by 2007 and market suppliers should be profitable. While there clearly are financial viability issues today for some project-financed facilities, this should not be the case in 2007.

More generally, it is unclear to me what basis Ms. Jaress could have for stating that APS acquiring the PWEC assets could affect the long term viability of competing suppliers. As I have testified, the acquisition should have no effect on the market price. If, *arguendo*, having a contract with APS beginning in 2007 is necessary for survival, then most of the suppliers are in trouble. By this logic, no matter who serves APS, all or some unstated subset of other suppliers could not be viable.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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[6] For example, generating plants counted in the PJM Interconnection can sell energy outside of it. However, counted capacity must be subject to a recall right such that energy will be available to PJM when needed.

RATEBASE EFFECT OF NEW UNITS

Year	Capacity (MW)	Average Rate Base ($/kW)	New Unit Cost ($/kW)	Years to Below Average
1	3200	500		
2	3200	484		
3	3200	467		
4	3600	511	662	10
5	3600	493		
6	3600	474		
7	4000	482	713	10
8	4000	463		
9	4000	444		
10	4600	470	768	13
11	4600	450		
12	4600	430		
13	4600	411		
14	5200	476	848	15
15	5200	455		
16	5200	433		
17	6000	478	913	NA
18	6000	455		
19	6000	433		
20	6800	477	983	NA
21	6800	453		
22	6800	429		
23	7600	477	1059	NA
24	7600	453		
25	7600	424		
26	8600	485	1140	NA
27	8600	454		
28	8600	427		
29	9700	495	1228	NA
30	9700	466		

NA = after the 30-year simulation
Inflation = 2.5 percent
30-Year depreciation

APS-14R

EXHIBIT
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admitted

REBUTTAL TESTIMONY OF CHARLES E. OLSON

On Behalf of Arizona Public Service Company

Docket No. E-01345A-03-0437

March 30, 2004

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REBUTTAL TESTIMONY OF CHARLES E. OLSON
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
Docket No. E-01345A-03-0437

Q. PLEASE STATE YOUR NAME.

A. My name is Charles E. Olson.

Q. ARE YOU THE SAME CHARLES E. OLSON WHOSE DIRECT TESTIMONY WAS FILED EARLIER IN THIS CASE?

A. Yes, I am.

I. PURPOSE OF TESTIMONY

Q. HAVE YOU REVIEWED THE TESTIMONY AND EXHIBITS OF RUCO WITNESS STEPHEN G. HILL, STAFF WITNESS JOEL M. REIKER AND FEA WITNESS MATTHEW KAHAL THAT WERE FILED IN THIS CASE IN FEBRUARY?

A. Yes, I have. I disagree with the conclusions of each of these witnesses on return on common equity and capital structure.

II. SUMMARY OF TESTIMONY

Q. DR. OLSON, WOULD YOU PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. Yes. The witnesses for RUCO, Staff and FEA all propose a common equity ratio that is too low and a return on common equity capital that does not meet the attraction of capital standard. With a 45 or so percent common equity ratio and a return on common equity of 9.00 to 9.85 percent, APS cannot attract capital on reasonable terms.

RUCO witness Hill relies on statistics from financial publications to support a 45 percent common equity ratio. These statistics ignore the profitable diversification of some of the diversified electrics, including pipeline and telecom operations. Second, some of the short-term debt held by these companies is properly attributed to Construction Work in Progress and not rate base. Third, snapshot style comparisons are not useful for ratemaking purposes. Fourth, some of the companies are in low growth areas and do not have to be in the debt market as often as APS. Finally, some of the companies are in or have been close to bankruptcy. Witnesses Reiker and Kahal also rely on statistical comparisons that either include utilities that are not in comparable circumstances as APS or may not have other elements of business and financial risk that warrant a higher equity ratio for APS, especially if the new power plants sought to be acquired by APS are not rate-based.

Mr. Hill's DCF is flawed because he relies on the sustainable growth approach which is not used by investors. Further, he then rejects his DCF result of 9.69 percent by reducing it based on flawed CAPM and modified earnings-price ratio results. Mr. Hill's Appendix D explains why CAPM should not be given any weight by commissions and then he uses it anyway. Finally, he cites FERC as support for other return on equity methods that they have explicitly rejected.

Mr. Reiker's DCF study is based in part on an unsupported dividend growth rate of 0.2 percent. His testimony does not offer precedent or literature support for the use of a combined historical/forecasted dividend growth rate. Further, his calculation includes companies which have reduced dividends- contrary to the constant growth assumptions of DCF. If this component of his growth rate is excluded, and even if his other adjustments were accepted, his recommendation rises to 9.9 percent before flotation costs. If he had, instead, used going-forward earnings growth, that figure would be higher yet. Mr. Reiker's CAPM is flawed for the same reason as Mr. Hill's.

Finally FEA witness Kahal uses a poor choice of comparable companies in his DCF study. One poor choice is Hawaiian Electric, literally an island utility with no interconnections with neighboring utilities, no coal or nuclear generation and no significant seasonal peaking. The other is Public Service of New Mexico ("PNM"), which has large merchant generation sales and a five-year stay-out plan. His recalculated return on equity is 10 percent, rising to 10.5 percent when financing costs are included. Mr. Kahal's CAPM is also conceptually flawed. Interestingly, however, it produces a higher result than his DCF study.

Messers. Hill, Reiker and Kahal all reject a flotation adjustment to the recommended return even though APS' parent, Pinnacle West, issued common equity in 2003. This adjustment for an actually incurred 2003 cost reduces each of the returns they recommend by 50 or so basis points.

III. REBUTTAL TO RUCO WITNESS HILL'S TESTIMONY

Q. BEGIN PLEASE WITH RUCO WITNESS STEPHEN G. HILL. WHAT RETURN ON COMMON EQUITY AND WHAT COMMON EQUITY RATIO DOES HE RECOMMEND?

A. Mr. Hill recommends a return on common equity of 9.50 percent in combination with a common equity ratio of 45.00 percent. Both of these recommendations would significantly understate APS' equity capital costs.

Q. THE COMPANY'S PROPOSED COMMON EQUITY RATIO IS 50.00 PERCENT. WHY DO YOU DISAGREE WITH MR. HILL'S RECOMMENDATION OF 45.00 PERCENT?

A. Mr. Brandt addresses the adjustments Mr. Hill made to his capital structure that resulted in the common equity ratio reduction. My testimony discusses Mr. Hill's comparison of APS and other electric utilities.

Mr. Hill begins at page 14 of his testimony with a discussion of how APS's common equity ratio compares to that of other companies in the electric industry. His comparison however includes companies with significant diversification, low bond ratings and non-utility investments. Some of the companies are in low growth areas and do not have to invest significant amounts in new plant and equipment. In contrast, APS has experienced customer growth at a rate well in excess of the industry average; this requires more frequent trips to the capital markets than slower growing companies. In my view, the data presented on his Schedule 2, page 2 are misleading. Mr. Hill uses these data to suggest that a common equity ratio in the low 40 percent range is adequate for APS to attract capital on reasonable terms.

Mr. Hill's presentation on Schedule 2, pages 3 and 4 is an "apples to oranges" comparison. He shows the bond ratings for the utility subsidiaries of many holding companies but uses the capital structures of the consolidated corporation. For example, CenterPoint Energy is listed by C.A. Turner (March 2004, pp. 11-12) as having a bond rating of BBB/Baa2 and an 11 percent common equity ratio. The 11 percent equity ratio is averaged with his other numbers even though CenterPoint has other subsidiary debt that is rated lower than investment grade and is in the process of restructuring under Texas PUC rules with a generation asset sale. Duke Energy and others have situations, such as significant trading or merchant generation related losses that have eroded their equity ratios and also make their inclusion inappropriate. What Mr. Hill needed was a set of data that accurately matches capital structure and bond ratings in an apples to apples manner. He has failed to do that.

The conclusion that the Commission is are supposed to draw from Mr. Hill's Schedule 2, page 3 of 4 is that a common equity ratio of 45 percent for APS is "generous" for the shareholders of Pinnacle West because the average common equity ratio of 40 percent for the electric companies and 39 percent for the combination utilities is lower than 45 percent. However such a conclusion is not warranted because the companies in Mr. Hill's groups have less risk that APS and can handle more debt. What Mr. Hill should have attempted is the type of analysis done by Mr. Brandt, which focuses on how ratings agencies evaluate leverage based not just on reported capital structures but also in consideration of "debt-like" obligations such as leases and long-term power agreements. I also note that Mr. Hill has not addressed the point I made in my Direct Testimony, which is that it is the inclusion of the new gas generation in rates that gave APS both the motivation and the ability to increase its leverage beyond that which existed at the end of the 2002 test period. Without such inclusion, the actual APS capital structure associated with its rate base would be that same 50% equity as then existed at the end of 2002.

Q. WHAT COST OF COMMON EQUITY CAPITAL DID MR. HILL DERIVE USING HIS DCF ANALYSIS?

A. As reported at page 28 of his testimony as well as at his Schedule 7, he found the DCF cost of equity to be 9.69 percent. He reached his conclusion using the concept of sustainable growth to estimate the growth rate component in his DCF approach.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THAT IT IS INAPPROPRIATE FOR MR. HILL TO PLACE SUBSTANTIAL RELIANCE ON THE SUSTAINABLE GROWTH RATE APPROACH IN HIS DCF ANALYSIS.

A. Mr. Hill has incorrectly developed a line of reasoning that supports the use of a particular variation to the sustainable growth rate approach in estimating the cost of common equity to public utilities. He begins at page 21 of his testimony with a statement that the "g" in the DCF model is "the expected sustainable growth rate." The "expected sustainable growth" is defined at Mr. Hill's Appendix B, page ii, and is equal to growth from retained earnings plus financing growth. His statement is not correct and his application of even the concept is flawed.

The cost of common equity capital is an expectational concept. This means that the growth rate used in the DCF formula to determine the allowable rate of return is the growth rate that is <u>expected</u> by the investor. The growth rate expected by the investor is not the same thing as "the expected sustainable growth rate" as that term is used by Mr. Hill. Whether this single measure of a utility's book value growth, that is, the sum of book value growth from earnings retention (BR) and book value growth from issuances of new equity at above book, is the limit to sustainable dividend growth is less important than the fact that this concept of growth is not necessarily in the minds of investors; indeed no one has ever proved that it is. It would have been fine for Mr. Hill to say that the investors would be unwise to expect more than his definition of "sustainable growth," but that is not what he did. Instead, as indicated at page 21, ll. 18-19, he defines the "g" in the DCF model as being "sustainable growth."

Mr. Hill also claims that Professor Myron Gordon has determined that "sustainable growth" embodies the underlying fundamentals of dividend growth and is therefore a primary measure of dividend growth to be used in the DCF model (Appendix B, pages i to ii). He supports his position by asserting that Dr. Gordon developed the DCF model and first introduced it into the regulatory arena. Again, Mr. Hill is incorrect. He is first incorrect in his claim that Dr. Gordon introduced the DCF technique into the regulatory arena. Rather, it was introduced by David Kosh, Herman Roseman and others. In fact, I used it numerous times before Dr. Gordon's book was published in 1974. Second, he clings to his particular "expected sustainable growth" approach in spite of more recent work, some of it by Dr. Gordon himself, that refutes it, both in general, and especially as done by Mr. Hill. By doing so, Mr. Hill refuses to acknowledge that finance theory has moved beyond the work that Dr. Gordon did as a consultant more than 25 years ago.

Q. WHY IS IT IMPORTANT TO RECOGNIZE THE ADVANCES IN FINANCE THEORY THAT HAVE OCCURRED IN THE PAST QUARTER CENTURY?

A. The function of the Commission in this proceeding is to determine a reasonable rate of return on common equity for APS. If the appropriate approach to estimating rates of return for regulated companies has changed significantly over the past 25 years the change should be reflected in the ratemaking process.

Q. WHAT IS WRONG WITH THE EXPECTED SUSTAINABLE GROWTH CONCEPT OR RETENTION GROWTH APPROACH AS IT IS SOMETIMES REFERRED TO?

A. There is nothing wrong with the theoretical notion that, on a very long-term basis, the value of a stock cannot grow more rapidly than the underlying fundamentals permit. In effect, the concept of expected sustainable growth tells us something about how investors ought to behave if they have the same long-term perspective. What is wrong, however, is Mr. Hill's adjustment of the market data to reflect his belief that utility stocks "ought" to trade in a narrow range around their underlying book value per share. However, when making DCF estimates of the cost of common equity capital, we are not interested in how investors <u>ought</u> to behave. Instead, we are interested in how they <u>are</u> behaving, given their anticipated investment time horizon. Therefore it is an essentially wrong application of his methodology to determine what return investors expect based on how he believes they ought to behave. What he should have done is to attempt to capture their actual growth rate expectations.

As I discussed above, the "sustainable growth" theory as used by Mr. Hill is based on the premise that utility stocks will always trade at a price that is somewhere around book value. Under this particular theory of cost of capital, investors should know that rates will be set in a way that brings the price of a utility stock back to near book value whenever it strays too far away.

Currently, market prices for many electric and gas utility common stocks, <u>including that of Pinnacle West Capital</u>, trade at prices that are well in excess of book value. Not only that, they have traded at prices in excess of book value for the last 15 or more years. This raises an interesting and fundamental question relative to rate of return regulation. If investors base their DCF growth estimates on growth rates that are "sustainable" in terms of book value, why have they bid utility stock prices to levels that are 40 percent or more above book value? And if you adjust downward those stock prices to correlate them with Mr. Hill's theory, you must also adjust upward the current dividend yields used in his DCF.

Quite obviously, investors are not assumed to be irrational; if they were, there would be no conceptual basis for the DCF model. However, it is equally clear that investors do not believe that utility stocks will continuously trade around book value either. Additionally, it is apparent that regulatory bodies do not necessarily believe share prices should be limited to book; if they did, market-to-book ratios would be far lower than they are today.

I addressed the question of high market-to-book ratios in my direct testimony. The point of that testimony was that investors clearly do not believe that Commissions will base rates of return on concepts such as sustainable growth and then apply those returns to book value type rate bases. If they did that or it was believed that they would do that, utility stock prices would have to come down. Thus, investors, contrary to Mr. Hill's testimony, do not base their growth expectations on his version of sustainable growth.

Q. HOW DO INVESTORS IN PUBLIC UTILITY STOCKS BEHAVE WHEN IT COMES TO ESTIMATING GROWTH?

A. Quite clearly if electric and other traditional public utility common stocks are trading well in excess of book value investors expect them to continue to trade at these levels. Rational investors would not buy these stocks with the expectation that share prices will decline. Further, the notion that investors believe that regulators will use the DCF method and apply it to original cost rate base in an effort to drive share prices down to book cannot be reconciled with the continued ability of utilities to trade at premiums over book.

As a group, investors have earned high returns on most common stocks in recent years and have come to expect returns of 15 or more percent on a going forward basis. In spite of the stock market declines of the recent past, price-earnings ratios and expected growth rates are still high; this means that investors are still optimistic and paying attention to analysts' forecasts. None of this should be taken to mean that regulatory bodies such as the Commission have to authorize returns on equity of 15 or more percent. But at the same time, no one should believe that the average utility investor is seriously basing his or her cost of capital determination on the sustainable growth approach as it is set forth by Mr. Hill. In my opinion, that is simply unrealistic.

Q. DOES DR. GORDON STILL CLAIM THE SUSTAINABLE GROWTH APPROACH IS THE BEST APPROACH?

A. I do not believe so. In an article titled "Choice Among Methods of Estimating Share Yield: The Search for the Growth Component in the DCF Model" (Journal of Portfolio Management, Spring 1989, p.50), Professor Gordon found that equity analyst estimates of the type I use provide more accurate estimates than three measure of historic growth.

Q. WHAT WOULD HAPPEN IF THE 9.5 PERCENT RETURN ON COMMON EQUITY THAT MR. HILL RECOMMENDS AS THE COST

OF EQUITY FOR HIS COMPARABLE COMPANIES WAS ACTUALLY EARNED BY EACH OF THE COMPANIES IN HIS GROUP?

A. Their earned returns would be lower, and this would cause some of them to make dividend cuts. I am not suggesting that the return on equity must always be set at a high enough level to maintain whatever the dividend levels of the comparable companies or Pinnacle West Capital may be at the moment. Rather, what I am saying is that it is unrealistic to believe that investors are doing DCF analysis using the method advocated by Mr. Hill. Investors are not paying prices above book value with the expectation of flat dividends or dividend cuts, or that share prices will decline to book. Instead, they are acting as if they believe that current market-to-book ratios will be maintained or increased. Their view is that enough will be earned on book value to do just that.

Q. ARE YOU SAYING THAT MR. HILL'S EXPECTED SUSTAINABLE GROWTH RATE ANALYSIS IS FUNDAMENTALLY ILLOGICAL AND INCONSISTENT WITH OBSERVED MARKET BEHAVIOR?

A. Yes. His approach is premised on the notion of investors and commissions focus on book values and authorized returns. But this cannot be the case, given actual market-to-book ratios. Quite obviously, investors just don't see it this way. They don't expect dividends to be cut; instead they expect them to go up, as does Mr. Hill. Yet this means that they are not performing the type of DCF analysis that Mr. Hill says they are.

Q. IN APPENDIX D OF HIS TESTIMONY, MR. HILL PRESENTS WHAT HE CALLS A MODIFIED EARNINGS-PRICE RATIO APPROACH TO THE COST OF COMMON EQUITY CAPITAL. IS HIS USE OF THIS

APPROACH USEFUL IN A CORROBORATIVE SENSE AS HE SUGGESTS AT APPENDIX D PAGE vii?

A. No.

Q. WHY NOT?

A. What Mr. Hill has done is resurrect an old approach to using what he defines as sustainable growth to determine rate of return on equity that was used more than 30 years ago by the Federal Power Commission ("FPC"). He then renamed it and incorrectly asserts that FERC has recently found this technique useful. Yet, in reality, this approach to ROE has not been considered reliable for years.

The modified earnings-price ratio approach that Mr. Hill sets forth in his application of DCF is really the "Midpoint Theory" that was developed and used at the FPC many decades ago. But, more than 30 years ago in Opinion No. 609, the FPC made these observations at 47 FPC 157:

> Opinions of this Commission, from *El Paso Natural Gas Company*, 28 FPC 688, 701, in 1962 forward, indicate that we have found the Midpoint Theory attractive. We have done so in part because it has tended to provide further support for our rate of return conclusions reached by other means. We have done so also because the theory appears to provide a test that is relatively simple to apply. Rate of return determinations are difficult, and they necessarily involve considerable subjectivity, and it is thus tempting to embrace techniques which appear to simplify their disposition.
>
> <u>We are now convinced, however, that the Midpoint Theory must be viewed with considerable skepticism</u>. See Commissioner Carver's concurring opinion in *United Gas Pipe Line Company*, Docket No. RP70-13, Opinion No. 589, December 9, 1970, 44 FPC 1556 at 1570. Not only does it provide so wide a range as to be entitled to little weight, as is the case in this proceeding,

> but we are persuaded that to the extent it may be based upon circular reasoning, it should be tested in its end result by the application of other evidence of comparable earnings. In determining just and reasonable rates of return, we must consider all relevant evidence and not rely solely upon the Midpoint Theory or any other theory.
>
> Earnings-price ratios and earnings-book ratios are in large measure, a function of the regulatory process. A utility's earnings-book ratio is determined, in effect, when this Commission, and others, establish allowances on equity. If the earnings-book ratio is above a fair and reasonable earnings level, the allowed rate of return is excessive; if the earnings-book ratio is below a fair equity return, the allowance should be increased. Since allowances are based on previously experienced test-year conditions, earnings-book ratios may be either too high or too low depending on whether variables affecting profitability improve or worsen in periods following the test year. As such, the earnings-book ratio may serve to indicate whether past regulation was either excessively tight or loose, but to say that the earnings-book ratio is, in some sense, an independent measure of a firm's demand for equity capital is illogical. [Emphasis supplied.]

Obviously, the FPC (now FERC) was expressing a very critical view of the Midpoint Theory as long ago as in Opinion No. 609. Moreover, the FERC does not currently rely on the Midpoint Theory to determine allowable rates of return.

Q. AT PAGE ix OF APPENDIX D, IN REFERRING TO HIS MODIFIED EARNINGS-PRICE RATIO ANALYSIS, MR. HILL MADE THE FOLLOWING STATEMENT: "THE FEDERAL ENERGY REGULATORY COMMISSION, IN ITS GENERIC RATE OF RETURN HEARINGS, FOUND THIS TECHNIQUE USEFUL AND HELD THAT UNDER THE CIRCUMSTANCES OF MARKET-TO-BOOK RATIOS EXCEEDING UNITY, THE COST OF EQUITY IS BOUNDED ABOVE BY

THE EXPECTED EQUITY RETURN AND BELOW BY THE EARNINGS-PRICE RATIO." IS THIS CORRECT?

A. Not at all. In Order No. 461, to which Mr. Hill referred, FERC referred back to an earlier Order (No. 442) and said that the shortcomings of the E/P ("earnings-price ratio") corroborative test remain. There is no reference in Order No. 461 to the technique being useful. More important, in Order No. 489, issued about a year after the Order referred to by Mr. Hill, the Commission made the following comment relative to market-to-book and earnings-price ratio evidence:

> FA Staff's presentation in this proceeding is substantially similar to those filed in the three earlier annual proceedings. Its analysis is not entitled to great weight because of its lack of precision. If one were to accept FA Staff's presentations at face value, they would appear to support nearly any cost of common equity estimate in the range of 9.38 to 13.70 percent. And, the 11.21 percent cost of common equity found reasonable by the Commission is certainly within that range.
>
> Cooperatives claim that an adjusted E/P ratio analysis corroborates its cost of capital estimate of 10.87 percent. However, the Commission notes that Cooperatives' adjusted E/P ratio is merely a derivative of the discounted cash flow model which uses book value growth, i.e., the "k = D/P+br+sv" model. The presentation is a tautology in that a minor reformulation of the primary model has been used to demonstrate the validity of the model itself. Therefore, Cooperatives' adjusted E/P analysis is not useful as corroborative evidence in this proceeding. See 51 Fed. Reg., 31,795, Footnote reference omitted.

After Order No. 489, the Commission issued Order Nos. 510 and 517 relative to generic rate of return. Neither Order mentioned the use of earnings-price ratios to determine ROE.

Q. IF THE MODIFIED EARNINGS PRICE RATIO IS MERELY CORROBORATIVE AS THE TITLE TO MR. HILL'S APPENDIX D

SUGGESTS, WHY DOES IT MATTER THAT FERC REJECTED IT MORE THAN 15 YEARS AGO?

A. While Mr. Hill suggests that this approach is merely corroborative, his final recommendation suggests otherwise. As indicated at pages 29-30 as well as at page 3, Mr. Hill rejects his DCF result of 9.69 percent and instead recommends a return on common equity of 9.50 percent. Clearly his non-DCF based methods impact his actual recommendation.

Q. IS THE MARKET-TO-BOOK ANALYSIS PRESENTED BY MR. HILL AT PAGES x-xi OF APPENDIX D A CHECK OF HIS DCF ANALYSIS?

A. No. All Mr. Hill has done is to apply his DCF analysis in a slightly different way. His equation at page xi is no more than dividend yield plus retention growth. What he has done, in the words of FERC, "is a tautology."

Q. IS MR. HILL'S CAPM ANALYSIS VALID AS AN ESTIMATE OF THE COST OF COMMON EQUITY?

A. No. I am unclear why Mr. Hill has relied on the CAPM. Mr. Hill himself does a very good job of explaining why beta is not a good measure of risk. This testimony, which is contained in his Appendix D, clearly demonstrates the weakness of beta as a measure of risk and therefore, the CAPM. Based on his own testimony, Mr. Hill should have concluded that the CAPM is not a suitable means of estimating the cost of common equity capital.

At page i of Appendix D, it is noted that the CAPM has certain fundamental theoretical shortcomings which reduce its usefulness. On the next page Mr. Hill points out that "the assumed linear relationship between beta, risk and return simply does not appear to exist in the marketplace." At page iii, Mr. Hill cites material from Value Line that indicates that "[b]eta, as the sole variable explaining returns on stocks, is dead." Finally, at page v, he notes that he uses the CAPM for information purposes and does not rely on the methodology as a primary equity capital cost estimation technique.

Yet after all the negative commentary in Mr. Hill's own testimony on CAPM, he nonetheless uses it to develop an equity cost at Schedule 8. Finally, at page 29 of his testimony he averages his CAPM result with his other methods to obtain his final range. This more than strains the credibility of his claim that he used CAPM only for "informational purposes."

Q. WAS HIS REDUCTION FROM 9.69 TO 9.50 REASONABLE GIVEN THE FACTORS HE DISCUSSED?

A. No. A more balanced analysis should have led him to the conclusion that his return should have been adjusted upward, probably to a range of 10.5 to 11.0 percent.

Q. PLEASE EXPLAIN THE BASIS FOR THIS CONCLUSION.

A. Certainly. To begin, there is no basis for a conclusion that APS has less financial risk than a reasonable group of comparable companies. Mr. Hill's conclusion that APS has less financial leverage is largely based on his Schedule 2, Pages 3 and 4. There, using data from C.A. Turner, Mr. Hill purports to show that other electric companies have more financial leverage than APS. However, this comparison is misleading for the reasons I also discussed earlier in my Rebuttal Testimony. And there are companies that simply are not comparable to APS.

First, some of the companies on that list are highly diversified. Second, some of the companies have pipeline or telecom operations. Third, the snapshot style comparisons that Mr. Hill makes are of limited value for ratemaking purposes. Fourth, some of the short-term debt being held by the companies on Mr. Hill's list is properly attributed to Construction Work in Progress and not rate base, which will have the effect of making the common equity ratios lower. Fifth, some of the companies are in low growth areas and don't have to be in the debt market as often as APS. Finally, some of the companies either are or have been close to bankruptcy.

Q. IF MR. HILL'S 9.69 PERCENT DCF RESULT SHOULD NOT BE ADJUSTED DOWN TO 9.50 PERCENT, WHY DO YOU THINK IT SHOULD BE ADJUSTED UPWARD TO A RANGE OF 10.5 TO 11.0 PERCENT?

A. I base this conclusion on two considerations. First, none of the electric companies in his sample group bear the regulatory and business risks of APS, which is in a high growth area with no power or fuel adjuster, a historic test period, and very significant regulatory lag. Second, there is no allowance for financing costs, market breaks or market pressure included in Mr. Hill's recommendations. I have explained in detail why such costs are appropriate in my Direct Testimony and will reiterate those reasons later in my Rebuttal. Suffice it to say at this point that there should be an allowance of 50-75 basis points for these items in the cost of capital. Based on the analyses done by Mr. Hill, his 9.69 percent DCF result should be increased by at least 75 to 125 basis points, which brings it into roughly the 10.5% to 11% range.

Q. AT PAGES 39-42 OF HIS DIRECT TESTIMONY, MR. HILL IS CRITICAL OF YOUR RISK PREMIUM ANALYSIS. DO YOU HAVE A RESPONSE?

A. Yes, I do. As a general matter, it would seem fair to say that Mr. Hill's testimony on this point is directed more at the concept of risk premium method than at my testimony. His first criticism of the method is that the method looks backward and thereby assumes that "past is prologue." While this is clearly true, to a degree, it is reasonable to believe that this is exactly what investors do. They look at the long history of stock returns exceeding bond returns by 6 or so percent and generalize that will continue. They also know that during the last 15 or so years, stock returns have been in the 15 percent range and expect this to continue. I do not know why Mr. Hill finds this to be inconsistent with his own DCF approach, which is essentially grounded in the use of past data.

Q. AT PAGES 30-32 OF HIS DIRECT TESTIMONY MR. HILL SUGGESTS THAT NO ALLOWANCE FOR FINANCING COSTS IS NECESSARY. DO YOU AGREE?

A. No. Mr. Hill's first objection to an allowance for financing costs is that none are anticipated. This is wide of the mark, as I explained in my direct testimony. Financing costs are properly compensated for in each and every rate case. As indicated by Dr. Gordon in <u>The Cost of Capital to a Public Utility</u>, the cost of capital should be increased proportionately to the financing costs. To quote Gordon, from page 166:

> The agency need only estimate the proportion that the proceeds per share on an issue bear to the price of the stock and adjust the allowed rate of return so that the price per share is the indicated ratio of the book value per share. If the proceeds on

> an issue are 91 percent of market price, the agency should maintain market price at about 110 percent of book value. The welfare of the stockholders is independent of the firm's stock financing rate, and the utility may be expected to set s to satisfy the demand for service.

Mr. Hill's second argument for not allowing financing costs is that Pinnacle West Capital's common shares sell at a price above book value. This is hardly a valid consideration in the context of Mr. Hill's own recommendation that would act to reduce that price to book value.

Mr. Hill next argues that financing costs are not out-of-pocket expenses. That is partially true but irrelevant. What is important is that the net proceeds of the issuance are less than the issuing price, whether because of underwriter fees (which <u>are</u> out-of-pocket) or market pressure.

Fourth, Mr. Hill now argues that the Gordon sustainable growth model includes an adjustment for financing costs in the growth rate. Quite clearly Dr. Gordon himself does not agree with this based on the material quoted from Dr. Gordon earlier in this answer.

The final argument presented by Mr. Hill is based on dated research that says investors have to pay brokerage fees that in theory may offset the new issuance fees. Perhaps that was true in the 1980's when the research he quotes was published. Today however, with online trading, brokerage fees are as little as a penny a share. Pinnacle West cannot issue new stock at that price.

Q. WOULD YOU SUMMARIZE YOUR CRITIQUE OF MR. HILL'S RECOMMENDED ROE?

A. Making even minimal adjustments to reflect financing costs, Mr. Hill would be in 10.5% to 11% range.

IV. REBUTTAL TO STAFF WITNESS JOEL M. REIKER'S TESTIMONY

Q. PLEASE TURN NOW TO THE TESTIMONY OF STAFF WITNESS JOEL M. REIKER. WHAT RETURN ON EQUITY DOES HE RECOMMEND IN HIS PREPARED TESTIMONY?

A. Mr. Reiker recommends a common equity ratio of 45.2 percent and a return on common equity of 9.00 percent.

Q. WOULD YOUR CRITICISM OF MR. HILL'S PROPOSED CAPITAL STRUCTURE ALSO APPLY TO MR. REIKER'S PROPOSED CAPITAL STRUCTURE?

A. Yes, and also to Mr. Kahal's, I will not bother to repeat the points I raised earlier and in my Direct Testimony.

Q. AT PAGE 6, LINES 5-17, MR. REIKER SUGGESTS THAT ARITHMETIC AND COMPOUND RETURNS HAVE BEEN BELOW 10 PERCENT, ON AVERAGE DURING THE LAST 200 YEARS. IS THAT INFORMATION USEFUL FOR PURPOSES OF THIS CASE?

A. No. The numbers he cites may or may not be accurate but they are of little relevance on a going forward basis. I would note that much of the 19th century was characterized by chronic deflation and no consistent set of accounting or financial reporting rules. Finally, the accuracy and completeness of such 19th century data are of questionable validity even assuming the data was compiled in a manner consistent with modern financial practices. Ibbotson Associates, for example, devoted an entire chapter in its 2003 SBBI Yearbook to discussing the problems in using data prior to 1926. And I am aware of no other regulatory body in the United States that uses such dated financial information to determine ROE in the 21^{st} century.

The Ibbotson data are generally more accepted as evidence of market returns than other information. These data show 20^{th} century returns of 12.2 percent for large company stocks, 13.8 percent for mid-cap stocks and 16.9 percent for small company stocks. These returns are total portfolio returns; individual company expected returns would be higher.

Mr. Reiker's attempt to place an artificial cap on utility returns of 10 percent based on a single study of what is largely ancient history, from a modern financial perspective, should be ignored. There are serious risks facing APS and an evaluation of these risks should be the focus of the rate of return part of this case without imposing arbitrary limits based on unreliable, outdated or momentary information.

Q. AT PAGE 9 OF HIS TESTIMONY MR. REIKER DISCUSSES HIS SELECTION OF COMPARABLE COMPANIES. WOULD YOU COMMENT ON WHAT HE DID AND PROVIDE AN OPINION CONCERNING THE REASONABLENESS OF HIS APPROACH?

A. Yes. Mr. Reiker started out with the 62 companies that are listed as being electric utilities by Value Line. According to his testimony, he then eliminated companies that have less than 65 percent of their revenue from electric operations, do not pay dividends and are not currently in bankruptcy. However according to Mr. Reiker's work papers, he also removed from his group companies for which

Value Line did not publish data prior to 1999 even if these data were available elsewhere from reliable sources. In my opinion there are significant deficiencies with his group of comparable companies that render it unusable as the basis for a conclusion on cost of equity in this case.

Second, there are clearly some mistakes in the revenue numbers used to determine his "comparable" group of companies. For example, he reports Ameren as having 118 percent of its revenue from regulated operations. How can that be? Dominion Resources is thrown out of his sample because he claims it has only 25 percent of its revenue from regulated operations. However, the March 2004 C.A. Turner Utility Report indicates 56 percent of Dominion's revenue comes from electric operations alone. Additionally Dominion owns a major gas pipeline that is FERC regulated. There are clearly problems with his numbers that cannot be reconciled with the underlying source data.

Q. MR. REIKER USES A SPOT OR ONE MOMENT IN TIME DIVIDEND YIELD AT OCTOBER 9, 2003 FOR PURPOSES OF CALCULATING HIS DIVIDEND YIELD. IS THIS A GOOD IDEA?

A. No. Regulators have long been aware that finance <u>theory</u> says that all information is included in stock prices at a moment in time. However, not all investors have the same information at the same moment in time, and all investors do not react to what information they do know at a single moment in time. Therefore, regulators have recognized the practical limitations on the theory of perfect market information and have averaged stock prices over a period of time such as three or six months, which matches the quarterly and semi-annual financial reports that provide most investors with much of the information they know about particular firms. The Commission would be wise to continue this practice. Further, for a piece of testimony that was filed on February 3, 2004, what is the magic of the second Thursday in October 2003? Mr. Reiker's recommendation is simply a poor and out of the mainstream regulatory practice and could often lead to arbitrary ROE recommendations based solely on a single day's stock price.

Q. AT PAGE 39 OF HIS TESTIMONY MR. REIKER CITES TESTIMONY BY DR. GORDON IN AN OLD FCC CASE AS SUPPORT FOR THE CONCEPT THAT A SPOT YIELD IS SUPERIOR TO AN AVERAGE OR A SMOOTHED YIELD. WHAT IS YOUR RESPONSE?

A. I recall a different rate case in which we both testified; in that era he used a smoothed yield. I also recall that the return on equity that was adopted by the NYPSC in that case was based on my testimony, not Dr. Gordon's.

Q. WAS YOUR DIVIDEND YIELD FOR IDACORP OVERSTATED AS MR. REIKER SUGGESTS AT PAGES 31-32 OF HIS PREPARED TESTIMONY?

A. No. My testimony was filed in June 2003, about three months before IDACORP reduced its dividend. Moreover, a market having the perfect intelligence posited by Mr. Reiker would never have permitted expected dividend yields to be "overstated."

Q. AT PAGE 32 MR. REIKER SAYS THAT YOUR RELIANCE ON ANALYSTS' ESTIMATES OF EARNINGS GROWTH IS INAPPROPRIATE BECAUSE IT ASSUMES THAT INVESTORS DO NOT LOOK AT OTHER INFORMATION SUCH AS PAST AND FORECASTED DIVIDEND GROWTH AND INTRINSIC GROWTH. IS HE CORRECT?

A. No. The analysts are clearly professionals and are keenly aware of historical information. This means that the historical information is already reflected in their estimates. Counting such information again clearly involves double counting and would unduly emphasis historical data in determining what is an essentially forward-looking concept, that is, as anticipated future growth. Even one of the sources cited by Mr. Reiker comes to this same conclusion:

> The superior performance by KFRG [which is defined earlier as analysts' forecasts of earnings growth per share] should come as no surprise. All four estimates of growth rely upon past data, but in the case of KFRG. A larger body of past data is used, filtered through a group of security analysts who adjust for abnormalities that are not considered relevant for future growth.

Gordon, Gordon and Gould, Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989, at pp. 50-55.

Q. AT PAGES 32-35 OF HIS TESTIMONY MR. REIKER IS CRITICAL OF YOUR USE OF A FIRST CALL GROWTH RATE OF 5.2 PERCENT. HE CITES VARIOUS PAPERS AND BOOKS THAT INDICATE THAT SUCH FORECASTS ARE OVERSTATED. WHAT IS YOUR RESPONSE?

A. My response is that whether or not it is believed by Mr. Reiker and others that earnings forecasts may be overstated, this belief misses the essential point of not confusing our own expectations with those of investors. And, analysts' estimates are used by investors, right or wrong. They drive stock prices and are therefore appropriate. This is *also* the position taken by one of Mr. Reiker's authorities:

> We have also seen that in spite of high error rates being recognized for decades, neither analysts nor investors who religiously depend on them have altered their methods in any way.

Davdi Dremand, *Contrarian Investment Strategies: The Next Generation at 115-116.*

Second, if I were not going to use analysts estimates the next choice would be intrinsic growth, which is similar in some respects to Mr. Hill's growth but without the improper adjustment to reflect market to book ratio. Mr. Reiker's 5.9 percent intrinsic growth rate is actually higher than my analyst consensus estimate. Using his own 5.9 percent intrinsic growth estimate, a DCF estimate in the low 11 percent range is clearly reasonable using even Mr. Reiker's questionable sample of "comparable" utilities..

Q. **AT PAGE 11, LINE 19 AND FOLLOWING, MR. REIKER MAKES THE CLAIM THAT FROM 1960 TO 2000 ELECTRIC UTILITY EARNINGS PER SHARE GREW AT A 1.8 PERCENT PER YEAR. THESE RATES ARE BELOW THE GROWTH RATES IN NOMINAL GDP AND THE CPI. DOES THIS INFORMATION SUPPORT THE CLAIM MADE AT PAGE 12, LINES 16-18, THAT FUTURE DIVIDEND GROWTH FOR ELECTRIC UTILITIES IN THE RANGE OF 5 TO 6 PERCENT WOULD BE UNUSUAL?**

A. No. The statistics cited by Mr. Reiker may be interesting to some, but they tell us nothing about the history of the industry from 1960 to 2000. Certainly he says nothing to support the view that history puts a cap on what investors expect for the future. Without this nexus, his answer is properly disregarded.

Q. **AT PAGE 13, LINES 2 – 6, MR. REIKER SAYS THAT HE ESTIMATED DIVIDEND GROWTH FOR HIS 33 COMPANIES BY CALCULATING THE AVERAGE GROWTH RATE IN DIVIDENDS PER SHARE FROM**

1997 – 2007. HE INDICATES THAT THE RESULTS ARE SHOWN IN SCHEDULE JMR – 4. IS THAT CORRECT?

A. Yes, that is what he says in his testimony. Further, Schedule JMR – 4 shows the 0.2 percent growth rate with no breakdown by company and a simple source reference to "Value Line". This calculation is misleading and cannot be relied upon for doing a DCF that would match investor expectations. Nine of the 33 companies in Mr. Reiker's sample have cut dividends during the period in question. Investors do not expect dividends to be reduced for the indefinite future. One should throw out the .2% figure and use the remaining measures of "g" found by Mr. Reiker. This would increase his DCF measure to 9.9%, even before consideration of financing costs.

Q. DOES MR. REIKER ALSO DO A CAPM STUDY OF THE COST OF COMMON EQUITY CAPITAL TO APS?

A. Yes, that study and its results are presented at pages 20-24 of Mr. Reiker's testimony. His CAPM estimate is 8.7 percent.

Q. IS HIS RESULT REASONABLE?

A. No. The CAPM is not a usable model for the determination of public utility rate of return. The record support for this claim can be found at pages ii to iv of RUCO witness Hill's Appendix D. There is no need for me to duplicate Mr. Hill's persuasive critique of CAPM. Needless to say, CAPM is wholly unreliable for public utility rate of return determination purposes.

Q. DOES MR. REIKER INCLUDE FINANCING COSTS?

A. No, and he is incorrect in excluding such financing costs for the same reasons I discussed earlier in my Rebuttal. This is also the case with the last ROE witness whose testimony I will rebut, Mr. Kahal.

Q. DOES THIS COMPLETE YOUR REBUTTAL OF STAFF WITNESS REIKER'S TESTIMONY?

A. Yes it does. I would now like to address the testimony of FEA Witness Kahal.

V. <u>REBUTTAL TO FEA WITNESS KAHAL'S TESTIMONY</u>

Q. WHAT DOES MR. KAHAL RECOMMEND WITH RESPECT TO THE APPROPRIATE COMMON EQUITY RATIO AND RETURN ON COMMON EQUITY?

A. Mr. Kahal recommends a common equity ratio of 45.05 percent and a return on common equity of 9.85 percent. His return on common equity was derived using the DCF and CAPM methods.

Q. AT PAGE 13 OF HIS DIRECT TESTIMONY MR. KAHAL SAYS THAT HE QUESTIONS THE USEFULNESS OF TWO OF YOUR COMPARABLE COMPANIES, PPL CORP AND PUBLIC SERVICE ENTERPRISES BECAUSE THEY OPERATE IN RETAIL ACCESS STATES. DOES MR. KAHAL SUPPORT HIS OPINION ON THIS ISSUE?

A. No. Mr. Kahal makes a two-sentence statement that suggests that utilities whose generation assets have been deregulated have a higher cost of capital than those that remain integrated. There is no basis for such a sweeping generalization. Some generation assets are clearly low risk and others higher risk. APS operates in a jurisdiction that has yet to finally determine about whether to regulate or deregulate generation assets, but it is also a direct access jurisdiction.

Q. HOW DID MR. KAHAL SELECT HIS GROUP OF COMPARABLE COMPANIES?

A. He began with my group and eliminated PPL Corp and Public Service Enterprises. Then he added four companies from the Value Line West group of companies, presumably because they are more comparable to APS than companies in the Value Line East and Value Line Central groups.

Q. IS THE APPROACH MR. KAHAL FOLLOWED REASONABLE?

A. There are many ways to pick comparable companies. I don't disagree with his inclusion of MDU and Black Hills Corporation. However, the use of Hawaiian Electric and PNM Resources is inappropriate.

Hawaiian Electric many be included in the Value Line West group, but quite clearly it is not located in the western part of the "Lower 48". In addition, it operates as an electrical island with vastly different characteristics than those of APS. It should not be included in a group of APS comparables.

PNM also should not be considered as being comparable to APS, even though it is located in New Mexico. PNM is operating under a rate stay out plan and is in the process of selling considerable amounts of generation into the competitive market. Mr. Kahal is completely inconsistent in throwing PPL Corp and Public Service Enterprise Group out of his comparables and then including PNM Resources.

Q. HAVE YOU RECALCULATED MR. KAHAL'S DCF RETURN WITH THSE TWO CHANGES?

A. Yes, I have. Mr. Kahal's dividend yield changes slightly when Hawaiian Electric and PNM Resources are removed, from 4.67 percent to 4.74 percent. His growth rate using the consensus data from First Call and Zacks is 5.15 percent. Factoring in the yield adjustment factor, the resulting return is 10.01 percent. If a reasonable figure of 50 basis points is added to this figure, for financing costs, the resulting return on equity is 10.5 percent.

Q. AT SCHEDULE MIK – 4, PAGE 3 AND MIK – 5, PAGE 3, MR. KAHAL USES PROJECTED GROWTH RATES FROM VALUE LINE, STANDARD AND POOR'S, FIRST CALL AND ZACKS. IS HE CORRECT IN USING ALL OF THESE SOURCES?

A. I don't believe so. Value Line provides information to its subscribers from its own analysts. Each analyst uses the basic Value Line model and covers 20 or more stocks in several industries. The time and coverage that can be devoted by Value Line analysts is limited and is therefore not of the same quality that would be available from a Bear Stearns or Goldman Sachs analyst. Further, the First Call and Zacks estimates are consensus figures derived by reviewing multiple estimates and not those of a single analyst. For example, the First Call growth estimate for Progress Energy for next year is the consensus of 13 analysts. Finally, Value Line does not provide a clearly defined earnings forecast as Mr. Kahal's Schedule MIK – 5, page 3 demonstrates. These are two forecasts and the difference between the two is huge.

The S&P forecast is also suspect. It is limited to a round percentage number and was taken from a subscription publication. This forecast is not available at any website that I am aware of; this means it is not available to most investors. In my view the consensus growth rates of First Call and Zacks are superior to the Value Line and S&P numbers.

Q. MR. KAHAL ALSO DERIVES AN EQUITY RETURN USING THE CAPM. AS SHOWN AT PAGE 1 OF SCHEDULE MIK – 6 HE DERIVES RETURNS OF 9.68 TO 10.57 PERCENT FOR APS IN THIS CASE USING THE CAPM. ARE THESE RESULTS REASONABLE?

A. In my opinion, the 10.57 percent return that Mr. Kahal derives as the upper end of his CAPM approach is clearly closer to the low end of a reasonable return range than the 9.85 percent that he recommends in this case. That being said, the CAPM is clearly a flawed model for the reasons I have already discussed at length.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

APS-15R

EXHIBIT

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APS-15R

admitted

BEFORE THE
ARIZONA CORPORATION COMMISSION

REBUTTAL TESTIMONY OF

KENNETH GORDON, Ph.D.

ON BEHALF OF

ARIZONA PUBLIC SERVICE COMPANY

March 30, 2004

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I. QUALIFICATIONS, SUMMARY AND CONCLUSIONS

Q. Please state your name.

A. My name is Kenneth Gordon.

Q. Are you the same Kenneth Gordon who submitted direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. I have been asked by Arizona Public Service Company ("APS" or the "Company") to respond to testimony submitted in this Arizona Corporation Commission ("ACC" or the "Commission") proceeding on certain regulatory policy issues related to the situation that APS unexpectedly finds itself in today, with some generation at APS and some generation at PWEC. Importantly, I point out that Staff and intervenor witnesses have not satisfactorily acknowledged the consequences of the Commission's decision to reverse a major element in its previous regulatory course, the scheduled transfer of APS's generation to a non-utility affiliate, Pinnacle West Energy Corporation ("PWEC").

While my direct testimony provided a policy framework on regulatory and vertical-integration issues, the Company's Application and the direct testimony of Steven M. Wheeler provides specific recommendations on the rate basing of PWEC's assets, as well as specific recommendations with respect to the reversal of the write-off of costs that had been made as part of a settlement. Further, the direct testimonies of Dr. William H. Hieronymus and Mr. Ajit P. Bhatti address planning and prudence issues related to the assets that are currently located at PWEC. These witnesses provided factual information that I draw upon in my own comments on these policy issues.

Q. As a matter of responsible and fair regulation, do you believe that the Commission can simply ignore the consequences of its Track A Order?

A. No. Good regulatory practice does not allow a regulator to change the regulatory rules without appropriate compensation after regulated utilities (and their affiliates and investors) have relied on those rules in good faith as they made investments or otherwise carry out clearly stated Commission policies. Given the sharp policy reversal manifested in the Commission's Track A Order, careful attention needs to be given to dealing with the consequences of that decision in a way that treats investors fairly and protects consumers.

Credible regulation provides clear rules of the game. The ability of a regulated utility to consistently attract capital is largely a function of the confidence that investors have in a jurisdiction's regulatory compact and therefore it is critically important that prudence issues and the overall returns to investors be addressed in a reasonable manner. Currently, the "loose ends" create regulatory uncertainty, which benefits neither the Company's investors or its customers. For example, Ms. Marylee Diaz Cortez, on behalf of the Residential Utility Consumer Office notes (p. 7), "[t]hese loose ends [status of the 1999 settlement, the electric competition rules, and the future share of retail electric regulation] are a detriment both to ratepayers and the electric utilities and put both in the unenviable situation of not knowing the rules of the game." I agree. The Track A Order, by reversing the planned transfer of APS's generation to PWEC, creates uncertainty about how the PWEC assets will be treated. From a ratemaking perspective, APS remains a traditional utility, with its rates regulated based on traditional rate-of-return-regulation/cost of service principles. This means that costs that were reasonably incurred to assure reliability should be recoverable by the utility. What is needed, going forward, is for APS to have the ability to provide efficient, safe, adequate, and reliable service to customers. Treating PWEC's generating assets in an equitable manner thereby benefits customers.

Q. Please summarize your testimony.

A. First, I discuss the regulatory policy issues associated with disentangling APS and PWEC from the current awkward and inefficient situation it faces with some generation at APS and some at PWEC, focusing on explaining why following the recommendations of Dr. Joseph P. Kalt and certain other Staff and intervenor witnesses would not be in the public interest.

Second, in light of the Commission's Track A policy decisions, I address the proper rate treatment for the regulatory assets that were written off in an earlier settlement and explain why it is appropriate to allow APS to recover the full costs of electric restructuring in rates. I provide rebuttal testimony on statements that have been made by Ms. Lee Smith on behalf of the Utilities Division of the Commission with respect to the rate treatment of the written-off regulatory assets, and to her recommendation that the full costs of preparing for electric restructuring should not now be recovered in retail rates.

II. REBUTTAL TOPICS

A. There are special regulatory circumstances involved here

Q. Dr. Kalt asserts (p. 11) that APS's request is "economically equivalent to a bail out of PWEC and PWCC [Pinnacle West Capital Corporation] at the expense of the electricity customers of APS."[1] Do you agree?

A. No, I do not. Aside from the economic reasonableness of rate-basing these assets, as described in the testimony of Dr. Hieronymus and Mr. Bhatti, this statement fails to acknowledge the special regulatory circumstances that the Track A Order[2] presents, thereby neglecting a critical issue addressed in my direct testimony.

PWEC built generation in Arizona believing that APS could not build and that new generation was needed in the state to meet customer demand. While PWEC built these generating plants assuming that its generation would be competitive,[3] it also expected that APS's generation would be moved to PWEC, which would allow the realization of economies of scale and scope (*e.g.*, the economies of operating a more balanced generation portfolio), the benefits of which could be shared by investors and customers. Rather than being a "bail out" of PWEC, the proposed ratemaking

[1] Direct testimony of Joseph P. Kalt on behalf of Arizona Competitive Power Alliance, February 3, 2004.

[2] Decision No. 65154 (September 10, 2002).

[3] Under the ACC's Electric Restructuring Rules that were in effect at the time of the Track A Order, all generation, both utility-owned and nonutility owned, would have operated on a competitive basis.

treatment, which recognizes that PWEC built these plants to provide an assurance that sufficient generating capacity would be available to meet customer demand, provides a reasonable opportunity for APS customers to benefit from the assured availability of these resources. Treating the APS/PWEC assets on a consistent, unified regulated basis is an appropriate way to proceed.

Q. Do the criticisms raised by Dr. Kalt (p. 8) and Mr. Tranen (p. 24)[4] on behalf of the Arizona Competitive Power Alliance recognize these special circumstances?

A. No. Leaving the current situation unchanged, as recommended by these witnesses, would deny the realization of economies of scale and scope flowing from the integrated operation of an integrated portfolio of the PWEC and APS generating assets. It is worth noting that the Commission, in its Track A Order, stated (p. 22) that it wanted to "take action in a manner that is fair to all parties and that protects ratepayers" and went on to say (p. 23) that "the wise course of action is to try to minimize the effects and figure out a way to move forward that will ultimately result in a market structure that performs efficiently and rationally, and that will result in the benefits that were promoted in the move to competition." I agree. To address the issues raised by the Track A Order, APS requested, in its rate case filing, that the Commission reunify the PWEC generation at APS under a common regulatory framework.

Q. Dr. Kalt argues (p. 38) that APS is "attempting to game the regulatory process in a manner that harms customers and enriches shareholders." Is this a valid characterization?

A. No. The special circumstances that are involved here, relating to the Commission's reversal of its electric restructuring policy in the Track A Order, cannot and should not be ignored. Moreover, no convincing evidence has been presented by Staff or intervenors that indicates that APS' customers would be harmed by this proposal. To the contrary, Dr. Hieronymus and Mr. Bhatti present clear empirical evidence that APS customers would benefit from the Company's rate-basing proposal.

[4] Direct testimony of Jeffrey D. Tranen on behalf of Arizona Competitive Power Alliance, February 3, 2004.

B. The ratemaking problems that arise from a regulatory reversal must be dealt with

Q. Does Dr. Kalt's direct testimony recognize properly that the Track A Order significantly changed APS's entirely reasonable regulatory expectations?

A. No. Dr. Kalt's failure to examine the Track A Order is a major omission. Understanding the consequences of the Track A Order's disruption of the balance of interests is crucially important. Efficient and fair resolution of the issues of how to deal with the consequences of having reversed an important element of its regulatory policies, the planned move of APS's generation to a non-utility affiliate, is needed.

The Track A Order disrupted the 1999 Settlement Agreement, which had provided for a complex—and inter-related—series of tradeoffs among the interested parties, and which had been agreed to by a number of parties and approved by the Commission. Having reversed major elements of its electric restructuring policy, the Commission now must resolve: (1) the rate treatment of the PWEC generating assets, which were built to be operated as part of a portfolio of existing and newly-built generating assets; (2) the rate treatment of the regulatory assets ($234 million pretax) that had been written off in conjunction with the larger settlement; and (3) the rate treatment of restructuring-related transition costs incurred to carry out the planned transfer of generating assets to PWEC. The intervenors' testimonies provide essentially no useful guidance to the Commission on how to resolve these issues in an efficient and fair way.

Q. Do you agree with Dr. Kalt's characterization (p. 9-10) that prudence is "fundamentally irrelevant" to this proceeding?

A. No. When considering rate base treatment for assets, it is my understanding that the Commission must consider whether the resulting rates are "just and reasonable."[5] In doing so, the Commission's obligation is to both customers and the Company. While a central focus of regulatory policies should be on consumers, careful attention to

[5] Pursuant to A.R.S. § 40-361, charges by public service corporations are required to be just and reasonable.

investors' interests is an essential part of that process and, if done properly, is directly aligned with long-term consumer interests.

In setting rates that are just and reasonable, the standard ratemaking approach is to provide the utility with an opportunity to recover the prudently-incurred costs (including a fair rate of return on capital) of providing utility services to customers.

Fairness requires that any imprudence be demonstrated objectively so that there will not be uncertainty about the regulatory decision. Evidence of failure to act prudently must be well grounded in law, economics, and public policy. Importantly, any prudence inquiry should be based on whether the decisions at the time they were made were reasonable under the circumstances, not based on 20/20 hindsight. Further, utilities should be held to an appropriate standard of reasonableness and not to a hypothetical ideal standard of perfection or optimization.

These are standard regulatory concepts, which the Commission has much experience in implementing.

C. As a regulated utility, APS continues to have an obligation to serve

Q. Dr. Kalt argues that the rate basing of the PWEC assets would fail to meet what he calls (p. 16) the public interest standard from an economic standpoint. Do you agree?

A. No, I do not. APS continues to have an obligation to serve customers in an efficient, safe, adequate, and reliable manner—and the assets that are currently owned by PWEC can play an important role in meeting that obligation.

The Track A Order made it clear that the Commission was responding to the lack of progress with wholesale competition in Arizona when it decided to change its regulatory policy with respect to the transfer of APS's generation to PWEC. Rate base/rate-of-return treatment is a standard feature of traditional utility regulation, which has operated reasonably well over many decades, given the utility's obligation to serve customers reliably in real time under all market conditions.[6] APS's "new-style" vertical

[6] Incentive ratemaking approaches, such as price-cap regulation, necessarily build off a fair starting point, which would normally be based on rate base/rate-of-return regulation.

integration accommodates competition as long as regulatory rules and institutional structures are in place to support wholesale (and, perhaps, retail) competition in the generation business. "New-style" vertically-integrated utilities, operating in competitive wholesale generation markets, will develop a least-cost mix of owned generation, contracts, and market purchases. In order to meet the obligation to serve, utilities traditionally have been vertically integrated, with committed generation sufficient to meet the needs of its customers in an efficient, safe, adequate, and reliable manner.

D. Rate base/rate-of-return regulation is being used in Arizona

Q. Dr. Kalt argues that APS's proposal would put its customers into the merchant power business (p. 24). Do you agree?

A. No. It is more accurate to say that, for the moment at least, Arizona regulation has moved back toward traditional utility regulation. Given the circumstances that APS is in today, with the Commission's Track A order effectively ending the electric restructuring process, the PWEC assets can reasonably be eligible for rate base treatment. Rate basing these assets would maximize the Commission's control over these assets, making them available to provide benefits to APS's customers within a traditional and familiar framework.

Q. Dr. Kalt argues that the PWEC assets are merchant plants (p. 29)? Do you agree?

A. No, in the circumstances this assertion is misleading and does nothing to help the Commission to resolve the current situation. At the time the PWEC assets were planned and constructed, all of APS's generation was to be transferred to a non-utility subsidiary and the newly-built PWEC generation was to be operated along with that generation. Thus, the PWEC assets were necessarily planned and constructed based in part on wholesale market expectations, as they would have been even if APS had been free to build them itself. Dr. Kalt recognizes this point, but fails to recognize that a key point of this proceeding is how best to deal with the Commission's reversal of its policy of moving APS's generation to non-regulated status.

The Commission chose, in its Track A Order, not to allow APS to move its generation to PWEC. On the other hand, based on its expectation that the Commission would follow through on its commitment to electric restructuring, PWEC had built generation, expecting that the new generation would be operated in tandem with the existing generation portfolio of APS. Because of a regulatory decision by the Commission, that expectation was not met. Now, given the Commission's policy reversal, Arizona is essentially back to a traditional regulatory model. In this context, rate base/rate-of-return regulation is the norm.

E. Traditional rate regulation is consistent with the current state of market development

Q. Dr. Kalt argues (p. 31) that rate basing the PWEC assets is inconsistent with competitive market development. Do you agree?

A. No. The Commission's Track A Order recognized (p. 29) that "[t]he wholesale market is not currently workably competitive; therefore, reliance on that market without recognizing its current uncertainty and limitations will not result in just and reasonable rates for captive customers." While I am a long-time supporter of efficient competition in wholesale (and, for that matter, retail) electricity markets, I cannot disagree with this conclusion. Given this context, which Dr. Hieronymus discusses in his rebuttal testimony, the Commission's decision to step back from electric restructuring, at least temporarily, is understandable.

Based on my general familiarity with the regulatory and market circumstances that are present in Arizona today, ownership of generation is an effective way to insulate customers from wholesale market risk. The Track A Order states (p. 23) that the "wise course of action is to try to minimize the effects and figure out a way to move forward that will ultimately result in a market structure that performs efficiently and rationally, and that will result in the benefits that were promoted in the move to competition." I concur, and believe that treatment of the APS and PWEC generation on a unified basis is preferable to the current inefficient situation, where some is considered regulated and some is not. By operating generation on an integrated basis, transaction costs can be reduced, risks can be more effectively hedged, and organizational efficiency and economies of scale and scope can be achieved. Organizing generation on a unified basis, that is as part of a single portfolio, can realize economies of scale and scope that benefit customers.

F. Traditional rate regulation prevents APS from exercising market power

Q. Dr. Kalt argues (p. 32) that rate basing the PWEC assets is part of an attempt to exercise vertical market power. Do you agree?

A. No. Dr. Kalt fails to recognize the regulatory limitations on any exercise of vertical market power. Simply put, APS's proposal means that APS's generation, transmission, distribution, and sale of electricity are fully regulated as utility activities. When a regulatory agency re-sets its direction, it must move forward in a way that treats the utility in a reasonable manner prospectively and which "settles up" the costs reasonably incurred in reliance upon the "old" policy. This can be accomplished by regulating the PWEC assets using traditional regulatory principles. PWEC's assets would be treated as part of APS's utility plant. Further, with respect to interactions between APS and other unregulated affiliates (other than PWEC, which would no longer be distinct from APS in Arizona), there are regulatory safeguards in place, such as unbundling requirements and codes of conduct, to assure that APS does not cross-subsidize or engage in preferential treatment.

With the Track A Order, the Commission would seem to have chosen to fall back on the traditional regulatory model, which means that there is little (if any) risk of APS exercising market power. As Ms. Marylee Diaz Cortez, on behalf of the Residential Utility Consumer Office notes (p. 5), the Track A Order "effectively rendered APS a vertically integrated utility once again."

Q. Do you agree with Dr. Kalt's assertion (p. 34) that APS's proposal constitutes a "textbook case" of the attempted exercise of market power?

A. No. APS is simply asking to apply traditional utility ratemaking to assets that were prudently incurred, as discussed by Company witnesses in this proceeding. This provides the Arizona Corporation Commission with an opportunity to fully oversee these generating assets.

G. Recovery of Regulatory Assets and Electric Restructuring Costs is Reasonable

Q. Utilities Division witness Ms. Lee Smith argues (p. 4) that the Company should not be able to reverse the write-off that APS took as part of the 1999 Settlement Agreement and recover those regulatory assets in rates on a going-forward basis. Do you agree?

A. No, I do not. It is my understanding that APS wrote-off certain "regulatory assets" that had otherwise been approved for recovery in rates and that it agreed to not seek recovery of all of its restructuring costs only as part of a comprehensive settlement. Regulatory assets can be recorded by a utility when a regulator acknowledges a cost but defers rate recovery to a future period. While Ms. Smith states (p. 6) that regulatory assets can be written off "with no independent impact" and that "the Company is essentially making a claim for a retroactive rate adjustment," I would view a regulatory failure to allow recovery of regulatory assets as a breach of a regulatory commitment. With the Track A Order, the settlement tradeoffs between the Company and the parties broke down, and the anticipated benefits to the Company were never realized. Given this change in circumstances, it is reasonable for the Company to be able to recover in rates the costs that the regulatory asset represents. While I am not an accountant, Ms. Smith's observation (p. 4) that net generation plant was not impacted by the Settlement seems to miss the point. Regulatory assets were written off, not net generation plant. Failure to provide for recovery of regulatory assets that would otherwise have been recovered in rates is clearly detrimental to the Company. As I explained earlier, when a regulatory agency re-sets its policy direction, it must more forward in way that treats the utility in a reasonable manner prospectively, which can be accomplished by providing for the recovery of regulatory assets and electric restructuring costs. Thus, APS should be able to recover in rates the regulatory assets and electric restructuring costs that have not already been included in rates.

Q. Do you have any other comments?

A. Yes. Attached as Schedule KG-1RB are copies of answers to data requests that I am incorporating into my testimony.

Q. Does this conclude your testimony?

A. Yes, it does.